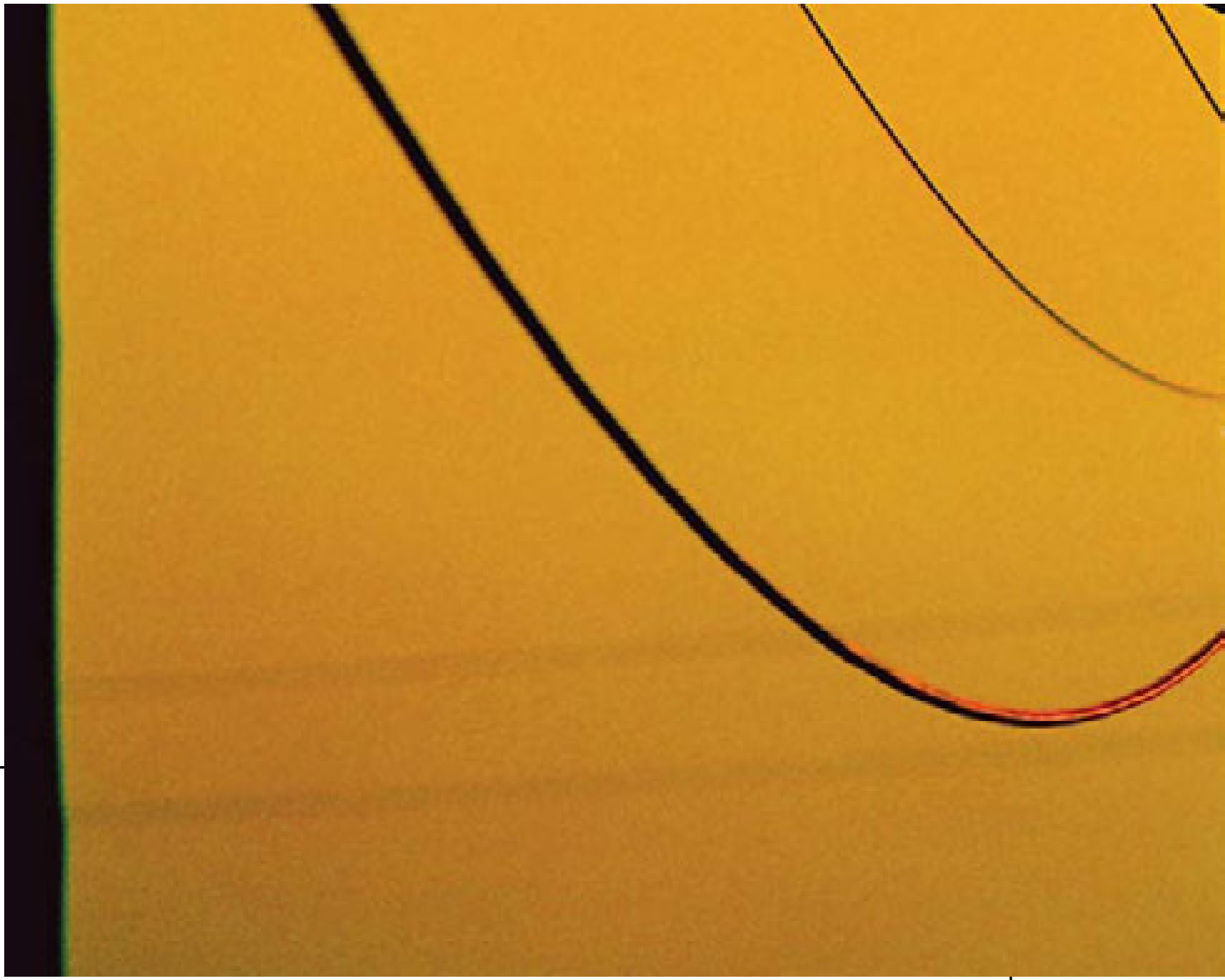


# 6 ELECTRICITY DISTRIBUTION

Jay Dickman (Corbis)

Most electricity customers are located a long distance from generators. The electricity supply chain thus requires networks to transport power from generators to customers. Chapter 5 provides a survey of high voltage transmission networks that move electricity over long distances. This chapter focuses on the lower voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities.

# 6 ELECTRICITY DISTRIBUTION

This chapter considers:

> the role of the electricity distribution network sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the distribution network sector
> financial outcomes, including revenues and returns on assets
> new investment in distribution networks
> quality of service, including reliability and customer service performance.

There are a number of ways to present and analyse data on Australia's electricity distribution networks. This chapter mostly adopts a convenient classification of the networks based on jurisdiction and ownership criteria. Other possible ways to analyse the data include by feeder—for example, a rural—urban classification. Section 6.6 includes analysis based on a feeder classification.

While this chapter includes data that might enable performance comparisons across networks, such comparative analysis should note that geographic, environmental and other differences can affect relative performance.

## 6.1 Role of distribution networks

Distribution networks move electricity from transmission networks to residential and business customers.[1] A distribution network consists of the poles, underground channels and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. While electricity moves along transmission networks at high voltages to minimise energy losses, it must be stepped down to lower voltages in a distribution network for safe use by customers. Most customers in Australia require delivery at around 230–240 volts.

Distribution networks criss-cross urban and regional areas to provide electricity to every customer. This requires substantial investment in infrastructure. The total length of distribution infrastructure is around 750 000 kilometres in the National Electricity Market (NEM) and around 100 000 kilometres in Western Australia and the Northern Territory—17 times longer than transmission infrastructure.

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but they do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services, and sell them as a package (see chapter 7). In some jurisdictions, there is common ownership of distributors and retailers, which are ring-fenced (operationally separated) from one another.

The contribution of distribution costs to final retail prices varies across jurisdictions, customer types and locations. The Queensland Competition Authority (QCA) reported in 2009 that distribution services account for about 36.5 per cent of a typical residential electricity bill.[2] The Essential Services Commission (ESC) of Victoria reported in 2004 that distribution can account for 30–50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.[3]

## 6.2 Australia's distribution networks

Australia has 16 major electricity distribution networks, of which 13 are located in the NEM. Table 6.1 provides summary details. Queensland, New South Wales, Victoria and Western Australia have multiple networks, of which each is a monopoly provider in a designated area. In the other jurisdictions, there is one major network. There are also small regional networks with separate ownership in some jurisdictions. Figure 6.1 illustrates the distribution network areas for Queensland, New South Wales, the Australian Capital Territory (ACT) and Victoria. Figure 4.1 in chapter 4 illustrates the network areas for Western Australia.

### 6.2.1 Ownership

Table 6.1 sets out ownership arrangements for Australian distribution networks. At June 2009:

- Victoria and South Australia's networks are privately owned or leased, and the ACT network has joint government and private ownership
- New South Wales, Queensland, Tasmania and the non-NEM jurisdictions of Western Australia and the Northern Territory have retained government ownership of the electricity distribution sector.



1 There are exceptions. Some large businesses (such as aluminium smelters), for example, can bypass the distribution network and source electricity directly from the transmission network. Conversely, embedded generators have no physical connection with the transmission network and dispatch electricity directly into a distribution network.

2 QCA (Queensland), *Final decision—benchmark retail cost index for electricity: 2009–10*, Brisbane, June 2009, p. 54.

3 ESC (Victoria), *Electricity distribution price review 2006–10, issues paper*, Melbourne, December 2004, p. 5.

Table 6.1 **Electricity distribution networks**

| NETWORK | LOCATION | CUSTOMER NUMBERS | LINE LENGTH (KM) | ENERGY DELIVERED (GWH), 2007–08 | MAXIMUM DEMAND (MW), 2007–08 | DISTRIBUTION LOSSES (%), 2007–08 |
|---|---|---|---|---|---|---|
| NEM REGIONS | | | | | | |
| QUEENSLAND | | | | | | |
| ENERGEX | Brisbane, Gold Coast, Sunshine Coast and surrounds | 1 270 734 | 51 349 | 20 879 | 4 142 | 5.7 |
| Ergon Energy | Country and regional Queensland | 766 453 | 146 339 | 13 813 | 2 313 | 6.5 |
| NEW SOUTH WALES AND THE ACT | | | | | | |
| EnergyAustralia | Inner, northern and eastern metropolitan Sydney and surrounds | 1 580 933 | 49 556 | 30 624 | 5 683 | 4.3 |
| Integral Energy | Southern and western metropolitan Sydney and surrounds | 853 322 | 33 299 | 17 586 | 3 317 | 4.1 |
| Country Energy | Country and regional NSW; southern regional Queensland | 780 222 | 205 133 | 11 973 | 2 329 | 7.0 |
| ActewAGL | All of the ACT | 158 455 | 4 696 | 2 799 | 599 | 4.5 |
| VICTORIA | | | | | | |
| Powercor | Western Victoria | 668 680 | 82 459 | 10 299 | 2 066 | 6.6 |
| SP AusNet | Eastern Victoria | 592 263 | 46 039 | 7 500 | 1 596 | 6.0 |
| United Energy | South eastern metropolitan Melbourne | 619 666 | 12 858 | 7 891 | 1 735 | 3.9 |
| CitiPower | Inner metropolitan Melbourne | 297 568 | 6 485 | 6 079 | 1 338 | 4.1 |
| Jemena | Western metropolitan Melbourne | 299 662 | 5 775 | 4 378 | 867 | 5.5 |
| SOUTH AUSTRALIA | | | | | | |
| ETSA Utilities | All of South Australia | 786 800 | 85 833 | 11 380 | 2 847 | 5.5 |
| TASMANIA | | | | | | |
| Aurora Energy | All of Tasmania | 265 524 | 24 641 | 4 487 | 1 073 | 1.1 |
| NEM TOTALS | | | | | | |
| NON-NEM REGIONS | | | | | | |
| WESTERN AUSTRALIA | | | | | | |
| Western Power | South western Western Australia | 973 516 | 85 182 | 14 500 | 3 420 | |
| Horizon Power | North western Western Australia | 37 508 | 7 747 | | | |
| NORTHERN TERRITORY | | | | | | |
| Power and Water | All of the Northern Territory | 74 097 | 7 311 | | | 7.0[5] |

| ASSET BASE (2008 $ MILLION)[1] | INVESTMENT—CURRENT PERIOD (2008 $ MILLION)[2] | CURRENT REGULATORY PERIOD | OWNER |
|---|---|---|---|
| 4 778 | 3 077 | 1 July 2005 – 30 June 2010 | Qld Government |
| 4 656 | 3 147 | 1 July 2005 – 30 June 2010 | Qld Government |
| 7 184 | 6 535 | 1 July 2009 – 30 June 2014 | NSW Government |
| 3 633 | 2 679 | 1 July 2009 – 30 June 2014 | NSW Government |
| 4 252 | 3 767 | 1 July 2009 – 30 June 2014 | NSW Government |
| 589 | 271 | 1 July 2009 – 30 June 2014 | ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International (Australia)) 50% |
| 1 849 | 905 | 1 Jan 2006 – 31 Dec 2010 | Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| 1 486 | 714 | 1 Jan 2006 – 31 Dec 2010 | SP AusNet (listed company; Singapore Power International 51%) |
| 1 387 | 550 | 1 Jan 2006 – 31 Dec 2010 | Jemena (Singapore Power International (Australia)) 34%; DUET Group 66% |
| 1 126 | 520 | 1 Jan 2006 – 31 Dec 2010 | Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| 657 | 239 | 1 Jan 2006 – 31 Dec 2010 | Jemena (Singapore Power International (Australia)) |
| 2 771 | 846 | 1 July 2005 – 30 June 2010 | Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| 1 072 | 566 | 1 Jan 2008 – 20 June 2013 | Tas Government |
| 2 574[3] | 1 392[3] | 1 July 2009 – 30 June 2012[4] | WA Government |
| | | | WA Government |
| 500[5] | | 1 July 2009 – 30 June 2014 | NT Government |

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2008 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2008 dollars.
3. Data from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.
4. At July 2009 Western Power's access arrangement for the period 2009–10 to 2011–12 was not finalised. Network prices for 2009–10, therefore, have been established under the previous access arrangement.
5. Includes transmission network assets.

Principal sources: Regulatory determinations and performance reports published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT) and the Utilities Commission (NT).

Figure 6.1

**Electricity distribution network areas—Queensland, New South Wales, the ACT and Victoria**

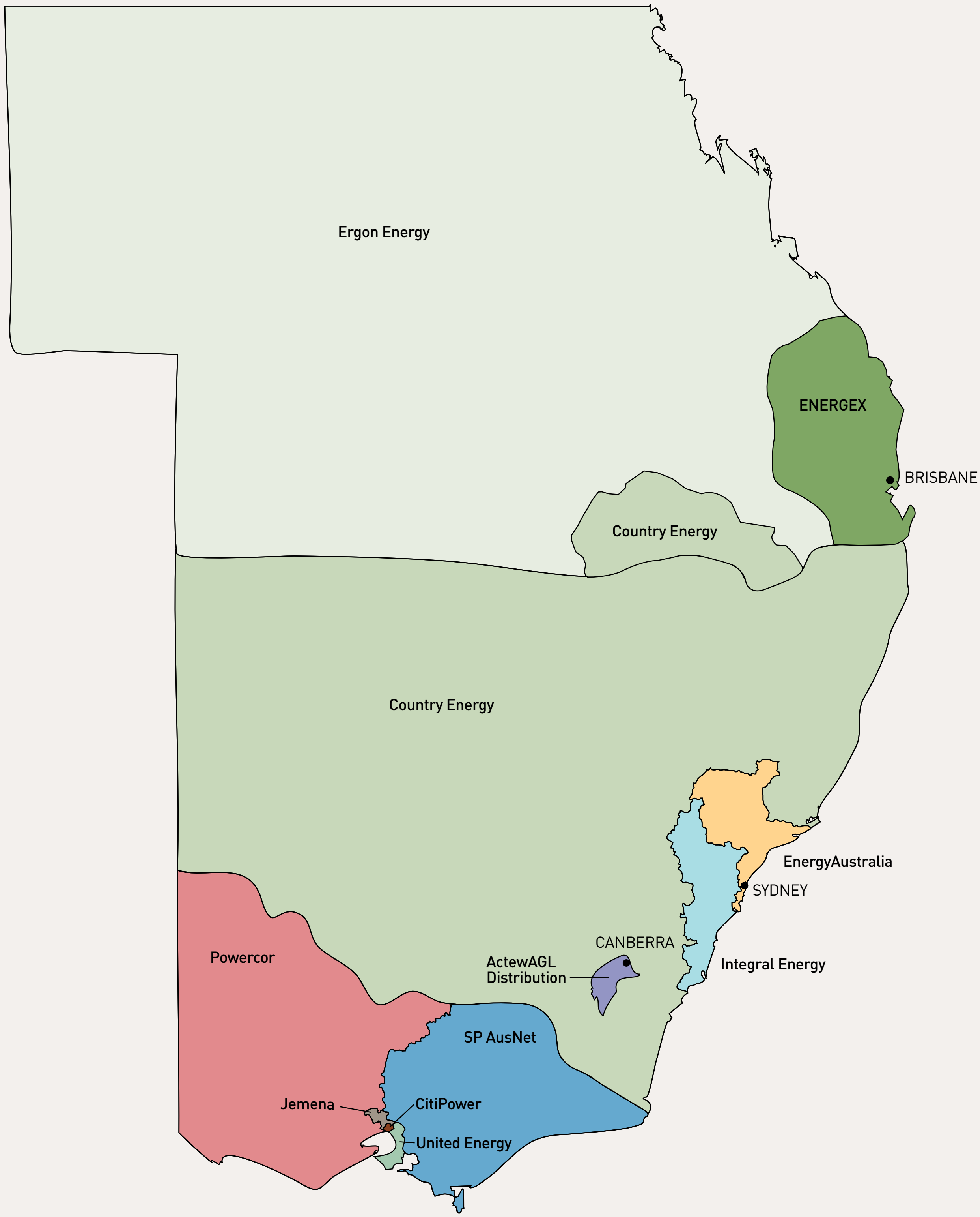
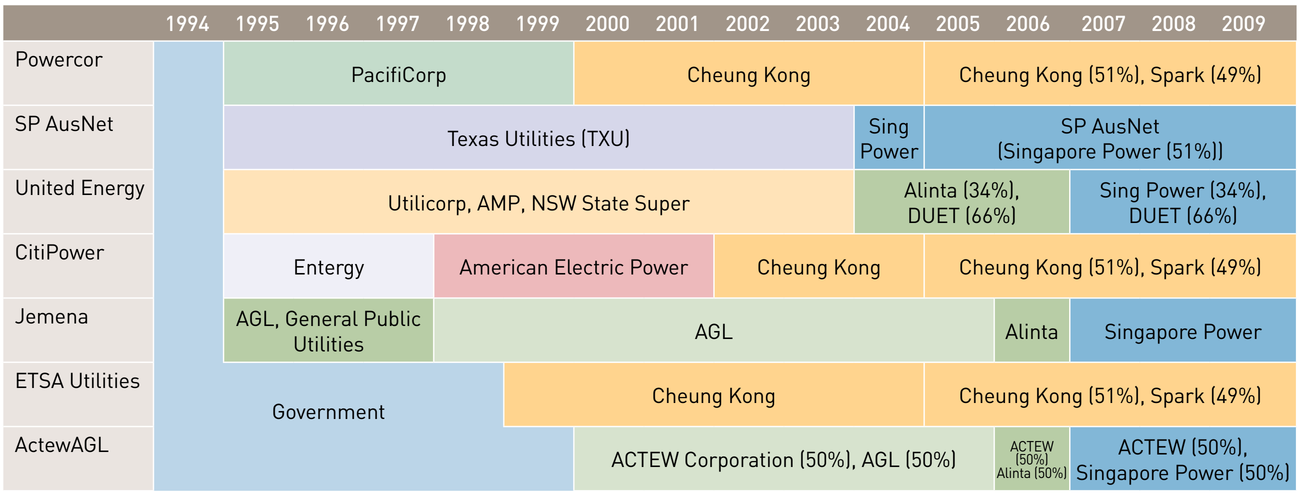


Figure 6.2

**Electricity distribution networks—private ownership**




Note: Some corporate names have been abbreviated or shortened.

Victoria's five distribution networks—Powercor, SP AusNet, United Energy, CitiPower and Jemena—are privately owned. The South Australian network (ETSA Utilities) is leased to private interests. Figure 6.2 tracks ownership changes since privatisation. At June 2009 there are two principal network owners:

> Cheung Kong Infrastructure and Hongkong Electric Holdings have a 51 per cent stake in two Victorian networks (Powercor and CitiPower) and a 200-year lease of the South Australian distribution network (ETSA Utilities). The remaining 49 per cent in each network is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.

> Singapore Power International owns a 51 per cent stake in SP AusNet, which owns Victoria's SP AusNet network. Singapore Power International acquired a second Victorian network (Jemena) and part ownership of a third network (United Energy) from Alinta in 2007. It also owns a 50 per cent share in the ACT distribution network (ActewAGL).

DUET Group has a majority interest in Victoria's United Energy network.[4] The minority owner, Singapore Power International, operates the network.

## 6.2.2 Cross-ownership

In some jurisdictions, there are ownership links between electricity distribution and other segments of the energy sector. In New South Wales, Tasmania and the ACT, common ownership occurs in electricity distribution and retailing, with ring-fencing arrangements for operational separation.[5] Queensland privatised much of its energy retail sector in 2006–07, but Ergon Energy continues to jointly provide distribution and retail services. In Western Australia, Western Power owns both electricity transmission and distribution assets. Horizon Power in Western Australia and Power and Water in the Northern Territory are vertically integrated electricity businesses.

The private electricity distributors also provide other energy network services. The most significant is Singapore Power International, which owns electricity transmission and distribution networks, and gas transmission and distribution pipelines. Cheung Kong Infrastructure has an interest in gas distribution pipelines through its 19 per cent stake in Envestra.

4 DUET Group comprises a number of trusts, for which Macquarie Bank and AMP Capital Holdings jointly own the responsible entities.

5 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.


Mark Wilson

## 6.3 Economic regulation of distribution services

Electricity distribution networks are capital intensive and incur declining marginal costs as output increases, thus realising economies of scale. This gives rise to a natural monopoly structure. In the NEM, the networks are regulated under the National Electricity Law (Electricity Law) and the National Electricity Rules (Electricity Rules) to manage the risk of monopoly pricing and ensure the reliability, safety and security of the power system.

On 1 January 2008 the Australian Energy Regulator (AER) acquired responsibility for the economic regulation of electricity distribution—previously the responsibility of state and territory regulators. The regulation of distribution networks in Western Australia and the Northern Territory remains under state and territory jurisdiction. Jurisdictional regulators continue to administer determinations made before 1 January 2008, except in Victoria, where the AER undertakes this role.[6] The AER is working with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period.

### 6.3.1 Regulatory process

Chapter 6 of the Electricity Rules sets out the timelines and processes for the economic regulation of distribution businesses. Distribution network businesses must periodically apply to the AER to determine their total revenue requirements for periods of at least five years. The regulatory process is lengthy to allow time for stakeholder consultation and the engagement of specialist consultants.

The process begins when the AER publishes a draft framework and approach paper for a network 24 months before the start of the next regulatory period. The paper is finalised in consultation with stakeholders six months after the draft paper is published. The AER first applied this process to the South Australian and Queensland networks in 2008.[7]

The framework and approach process acknowledges differences in the regulation of each network. This partly reflects historical differences in regulatory approach across the jurisdictions. In the transition to national regulation, it is important to clarify these differences upfront and indicate how the AER will approach each determination. The process also enhances transparency and certainty by giving stakeholders an opportunity to understand and comment on the regulatory approach.

The framework and approach process clarifies high level regulatory mechanisms and aims to assist network businesses to prepare their proposals. While the process sets out the AER's thinking at the time, there is scope for the AER to modify its position on some mechanisms. In summary, of the positions developed through the framework and approach process:

> the control mechanism for setting a network's revenues or prices remains binding
> the classification of services remains binding unless the AER considers there are good reasons to change it
> all other positions are not binding.

Once the framework and approach process is completed, the network business must submit a regulatory proposal and a negotiation framework. This must occur at least 13 months before the end of the current regulatory period. The AER then assesses the proposal, typically with help from specialist consultants, and releases a draft determination for further consultation. It must release a final determination two months before the beginning of the upcoming regulatory period.



6 This administration of determinations after they have been made involves assessing pass-through applications, approving prices, and assessing and reporting performance. State and territory regulators can elect to transfer the administration of current determinations to the AER. In Victoria, several of these functions have been transferred, and the AER will administer the Electricity Distribution Price Determination applicable until 31 December 2010. In other states and territories, jurisdictional regulators will continue to administer current determinations.

7 The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

### Box 6.1 New South Wales and ACT distribution determinations

In April 2009 the AER released its first determinations for the distribution sector—for the New South Wales and ACT networks. The determinations provide for, in real terms, $13 billion of capital expenditure across the three New South Wales networks and $270 million for the ACT network over the period 2009–10 to 2013–14. The allowances are around 70 per cent higher than capital expenditure for the preceding five years.

The justification for higher investment varied across the networks but included:

- network augmentations to meet rising peak demand across the networks and significant load growth in regions including the north coast, the Sydney central business district and western Sydney
- the need to meet enhanced licensing conditions for network security and reliability
- the replacement of ageing and obsolete assets.

The AER also approved significantly higher allowances for operating and maintenance expenditure—over $6.5 billion for the regulatory period across the four businesses. This reflects assessments of prudent expenditure requirements for the networks.

The overall revenue allowance across the four businesses is almost $19 billion, around 60 per cent higher than for the previous regulatory period (in real terms). While this is a considerable increase, the allowances are lower than those sought by the businesses and those foreshadowed in the AER's draft report. This decision reflects revised economic forecasts (factoring in the effect of the global financial crisis) of easing demand growth.

The determinations will result in an increase in average residential electricity bills of up to $1.50 per week in 2009–10.

The New South Wales distribution businesses lodged appeals with the Australian Competition Tribunal over aspects of the decisions. The appeals may result in amendments to the determinations.

**Figure 6.3**
**Determination processes for electricity distribution networks**

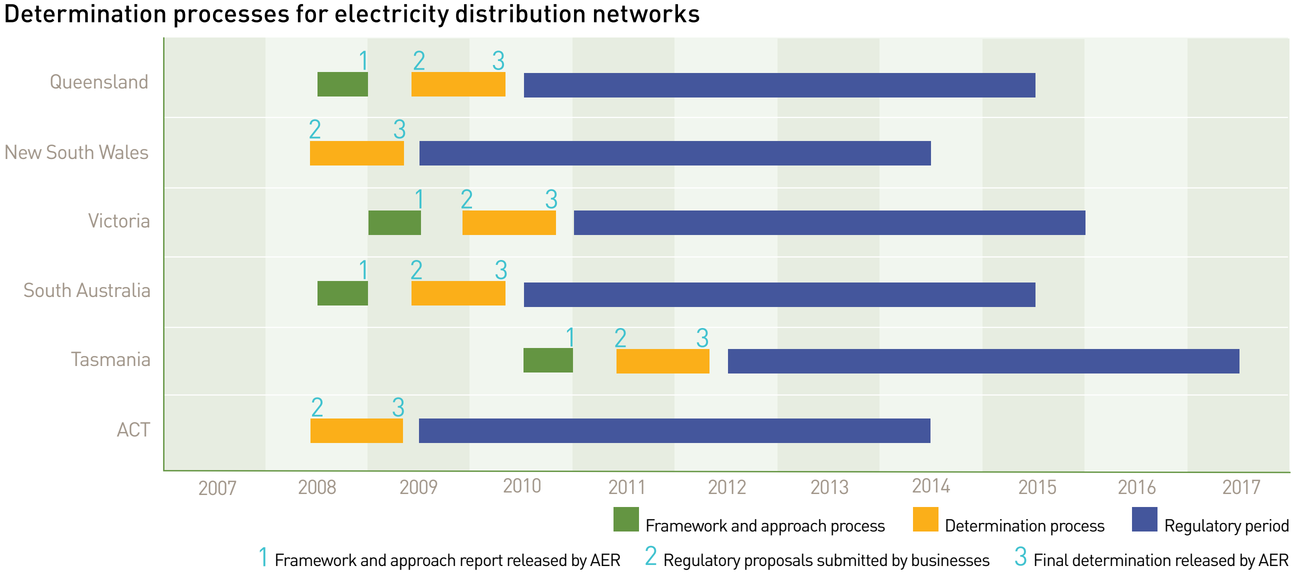


Figure 6.3 shows the regulatory timelines for each network. The AER completed its first electricity distribution reviews, for businesses in New South Wales and the ACT, in April 2009 (box 6.1). It has started work on determinations for the Queensland and South Australian networks, following the submission of regulatory proposals to the AER in June 2009. This process will determine each business's annual revenue requirements for the five year period from 1 July 2010.

For the Victorian networks, the next determinations are due to take effect on 1 January 2011. The AER has completed the framework and approach process and will complete the formal review process in late 2010.

### 6.3.2 Regulatory approach

The AER's regulatory approach involves setting a ceiling on the revenues or prices that a distribution business can earn or charge during a period, typically five years. The Electricity Rules require the use of incentives to optimise performance, but allow the regulator to choose the form of incentive. Regulatory frameworks currently used in Australia include revenue yield models (which control the average revenue per unit sold, based on volumes or revenue drivers) and weighted average price caps (which allow flexibility in individual tariffs within an overall ceiling).[8] Table 6.2 illustrates the range of available approaches.

**Table 6.2 Control mechanisms available to electricity distribution businesses**

| FORM OF REGULATION | HOW IT WORKS | REGULATORY POSITION AT 1 JULY 2009 | |
|---|---|---|---|
| | | REGULATOR | DISTRIBUTION BUSINESSES |
| Price cap or tariff basket | Sets a ceiling on distribution tariffs/prices. For a weighted average price cap, the business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling. | Essential Services Commission (Vic), administered by the AER | Powercor<br>SP AusNet<br>United Energy<br>CitiPower<br>Jemena |
| | There is no cap on the total revenue that a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales. | AER | EnergyAustralia<br>Integral Energy<br>Country Energy |
| Revenue cap | Sets the maximum revenue that a business may earn during a regulatory period. It effectively caps total earnings. This mirrors the approach used to regulate transmission networks. The distribution business may set individual tariffs such that total revenues do not exceed the cap. | Queensland Competition Authority | ENERGEX<br>Ergon Energy |
| | | Office of the Tasmanian Economic Regulator | Aurora Energy |
| | | Economic Regulation Authority (WA) | Western Power |
| Maximum average revenue cap | Sets a ceiling on average revenues during a regulatory period. Total prescribed distribution service revenues are capped each year at the average revenue allowance for a year multiplied by actual energy sales. Tariffs must be set to comply with this constraint. | AER | ActewAGL |
| Revenue yield control | Links the amount of revenue that a business may earn to the volume of electricity sold. Total revenues are not capped and may vary in proportion to the volume of electricity sales. | Essential Services Commission of South Australia | ETSA Utilities |
| | The business is free to determine individual tariffs—subject to tariff principles and side constraints—such that total revenues do not exceed the average. | | |
| Schedule of fixed prices | Sets a list or schedule of prices for each individual service provided by the distribution business. | | |

8 Some mechanisms are reflected only in past determinations by jurisdictional regulators.

As noted in table 6.2, the regulatory approach varies across networks. The AER's April 2009 determinations applied a weighted average price cap (which places a ceiling on the prices of distribution services during a regulatory period) to the New South Wales networks, and an average revenue cap (which sets a ceiling on revenue yields that may be recovered during a regulatory period) to the ACT network.

Recent AER framework and approach papers determined that the South Australian and Victorian networks will be subject to a weighted average price cap. The Queensland networks will be subject to a revenue cap. The AER has consulted with the relevant business to settle on these approaches.

In applying any of the forms of regulation in table 6.2, the AER must forecast the revenue requirement of a business over the regulatory period. To do this, it uses a building block model that factors in:

- investment forecasts (capital expenditure)
- the operating expenditure allowances that a benchmark distribution business would require if operating efficiently
- asset depreciation costs
- a commercial return on capital
- taxation liabilities.

In setting these elements, the AER has regard to demand projections, price stability, the potential for efficiency gains in cost and capital expenditure management, service standards and other factors. While jurisdictional regulators have taken varying approaches to specific building block components, the AER has developed a consistent method for all future revenue determinations.

Since assuming responsibility for the economic regulation of distribution networks, the AER has published models and guidelines to assist stakeholders. These include:

- a post-tax revenue model, which takes the cost estimates (or building blocks) for a network and determines the annual revenue requirement needed in each year of the regulatory period
- a roll-forward model, which determines a network's opening regulated asset base (RAB), taking account of capital expenditure, asset disposal and depreciation over the previous regulatory period. The model also establishes annual RAB forecasts for the coming regulatory period.
- a decision on the parameters of the weighted average cost of capital (WACC) model, which determines the return on capital that a regulated network may recover.[9] The WACC model sets an efficient benchmark for elements including equity raising and debt costs faced by a business when raising finance. The WACC model applies to all distribution businesses that submit regulatory proposals after 1 May 2009.
- cost allocation guidelines, which outline the cost allocation method for a network and the basis on which the AER will assess that method
- an issues paper on annual regulatory reporting requirements, with a view to publishing a regulatory information order in 2009. The order will set out guidance and protocols for the annual collection and submission of information to the AER for comparative analysis.

The AER has also developed incentive schemes to apply to distribution businesses:

- A *national efficiency benefit sharing scheme* provides incentives for distribution businesses to achieve efficient operating and maintenance expenditure in running their networks. The scheme shares efficiency gains between the business and customers (through lower prices). The AER indicated in its framework and approach papers that it will apply the scheme to businesses in Queensland, South Australia and Victoria from the next regulatory control period (see also section 6.5.3).

9 AER, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, final decision*, Melbourne, May 2009.

- A *national incentive scheme on service target performance* provides incentives for businesses to maintain or improve service performance across the network. It acts as a counterbalance to the efficiency benefit sharing scheme so businesses do not reduce costs at the expense of service quality. The scheme focuses on supply reliability (the frequency and duration of network outages) and customer service. If service performance falls below target, a business is penalised; if performance is above target, the business earns rewards. The scheme also includes a guaranteed service level (GSL) component, under which payments are made directly to customers when service performance falls below threshold levels. The service standards scheme applies as a paper trial in New South Wales and the ACT in the current regulatory period (that is, targets will be set but no financial penalties or rewards will apply). The AER indicated in its framework and approach papers that it will apply the service performance scheme to the Queensland, South Australian and Victorian networks in the next regulatory period (see also section 6.6.2).
- *Jurisdictional demand management incentive schemes* provide incentives for network businesses to implement efficient non-network approaches to manage demand. The schemes offer allowances for projects or initiatives that reduce network demand. In some jurisdictions, the schemes allow businesses to recover revenue that has been forgone due to successful demand reduction initiatives. No business is compelled to take up the scheme, with the allowance provided on a 'use it or lose it' basis. The AER has developed individual demand management schemes for New South Wales and the ACT, South Australia and Queensland, and Victoria (see also section 6.8.1).

## 6.4 Distribution investment

New investment in distribution infrastructure is needed to maintain and, where appropriate, improve network performance over time. Investment covers network augmentations to meet rising demand and expand into new regional centres and towns. It also covers upgrades to improve the quality of existing networks by replacing ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figure 6.4 shows the opening RABs and forecast regulated investment over the current regulatory period for the major networks.[10] The combined opening RABs of distribution networks are around $39 billion, more than double the valuation for transmission infrastructure. Investment over the current regulatory cycle for the networks is forecast at around $25 billion.[11]

Many factors can affect the value of RABs and investment, including the basis of original valuation, historical network investment, the age of a network, geographic scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

Figure 6.5 charts annual investment in regulated assets in each network, using actual data where available and forecast data for other years. The forecast data relate to proposed investment that the regulator has approved as efficient at the beginning of the regulatory period. The forecast data are smoothed over the regulatory period to remove the significant volatility often evident in the annual forecast data. The charts depict real data in June 2008 dollars.

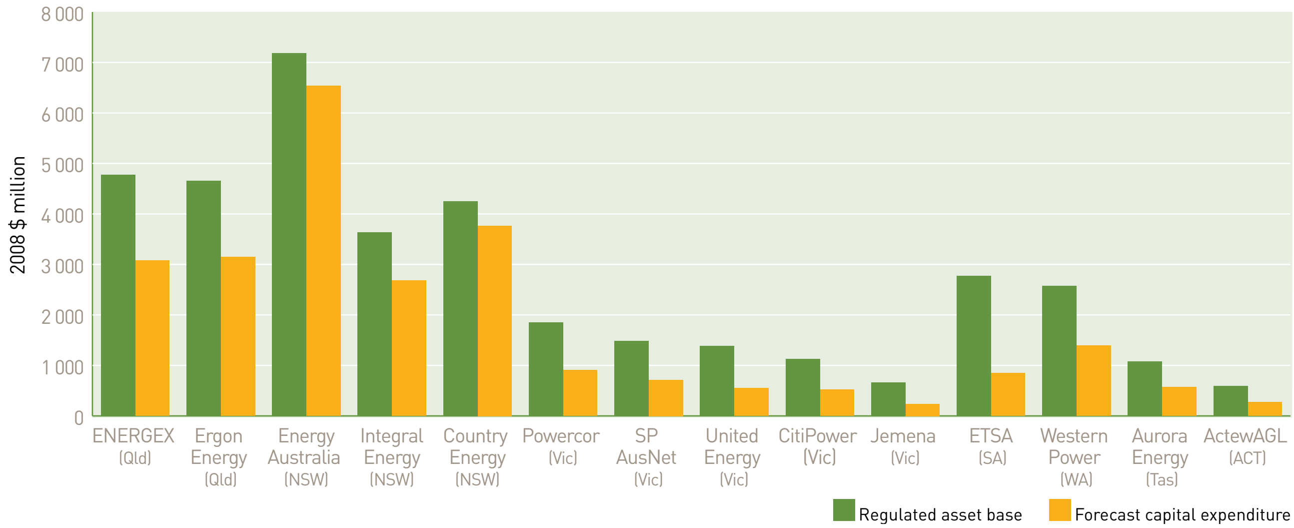


10 Regulated investment in most networks does not include capital contributions. Although this expenditure forms part of the overall investment in a network, the distribution business does not incur the development costs and, accordingly, does not receive a return on those assets. At the end of the regulatory period, the RAB is adjusted to reflect new regulated investment that has occurred.

11 Investment estimates are for the current (typically five year) regulatory periods. The RAB and investment values are in June 2008 dollars.

Figure 6.4

**Electricity distribution network assets and investment—current regulatory period**




Notes:

The regulated asset base is the opening asset valuation for the current regulatory period. Forecast capital expenditure is for the current regulatory period.

The regulatory period is 4.5 years for Aurora Energy (Tas), three years for Western Power (WA) and five years for other networks.

Data for Western Power are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12.

All values are converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ERA (WA).

In summary, investment in the NEM jurisdictions was forecast at over $4.1 billion in 2008–09, increasing to almost $4.8 billion in 2009–10. In Western Australia, $380 million of investment was forecast in 2008–09, with the Economic Regulation Authority proposing investment by Western Power of $450 million in 2009–10. Investment has risen steadily during the current decade in most networks. This has generally been accompanied by stable reliability outcomes.[12]

On average, investment during the current regulatory cycle is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales. Different outcomes across jurisdictions reflect a range of variables, including forecast demand, the scale and age of the networks, and investment allowances in historical regulatory determinations.

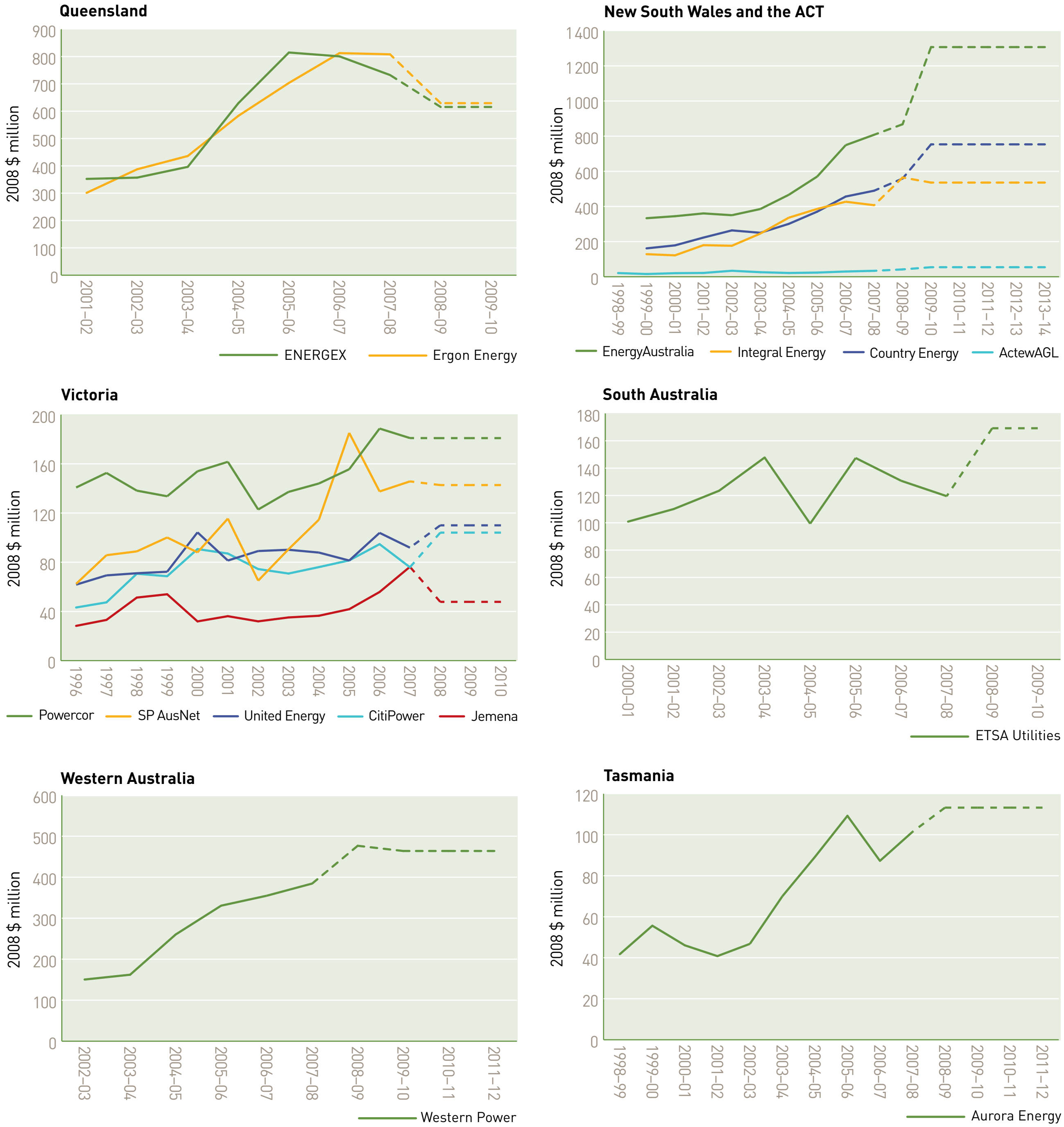
Box 6.1 includes a summary of the New South Wales and ACT distribution determinations released by the AER for the period 2009–10 to 2013–14.

There is some volatility in the investment data, reflecting a number of factors. In particular, investment is somewhat lumpy as a result of the one-off nature of some capital programs. More generally, the network businesses have some flexibility in managing and reprioritising their capital expenditure over the regulatory period. Transitions between regulatory periods, and from actual to forecast data, also result in some data volatility—for example, network businesses tend to schedule a significant portion of investment in the early stages of a regulatory period, although some projects may be subsequently delayed.

12 See section 6.6 and figure 6.10.

Figure 6.5

**Electricity distribution network investment**




Notes:

Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as set out in regulatory determinations (except for Western Australia, for which forecasts for 2009–10 to 2011–12 are based on the ERA's draft decision for Western Power). Forecasts are of average capital expenditure over the regulatory period.

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), the ERA (WA) and OTTER (Tas).

In addition to regulated investment undertaken by the distribution businesses, market participants can also fund new investment in the networks. These capital contributions can form a significant proportion of new network investment—for example, they have typically accounted for over 15 per cent of total distribution network investment in Victoria and over 25 per cent of investment in South Australia.

For most distribution businesses, investment funded through capital contributions sits outside the RAB and the businesses do not earn a return on the assets. In Queensland and Western Australia, however, distribution businesses have capital contributions included in the RAB. The revenue allowance of these businesses is adjusted to ensure overall returns reflect the actual business activity of the network.[13]

## 6.5 Financial performance of distribution networks

Financial data on distribution networks are available from two main sources—performance reports and regulatory determinations. Until recently, all jurisdictional regulators published annual reports on electricity distribution networks, covering financial and service performance.

With the move to national regulation in 2008, the AER will play a role in public reporting on the financial performance of the networks. Initial reports will be prepared for the Victorian networks for the 2009 reporting year, and for the New South Wales and ACT networks for 2009–10. The AER will consult with stakeholders to develop an appropriate reporting framework.

Regulatory determinations include historical financial data for the preceding regulatory period and forecast outcomes.

### 6.5.1 Revenues

Figure 6.6 charts revenues for distribution networks, based on actual results where available and otherwise using regulatory forecasts. Allowed revenues are tending to rise over time as underlying asset bases expand to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around $6.1 billion in 2008–09, a rise of about 4 per cent in real terms over the previous year. A further rise of about 12 per cent in real terms ($6.8 billion) is forecast for 2009–10.

In Western Australia, Western Power's allowed revenues in 2008–09 were around $400 million. It has proposed an increase to over $600 million in 2009–10.

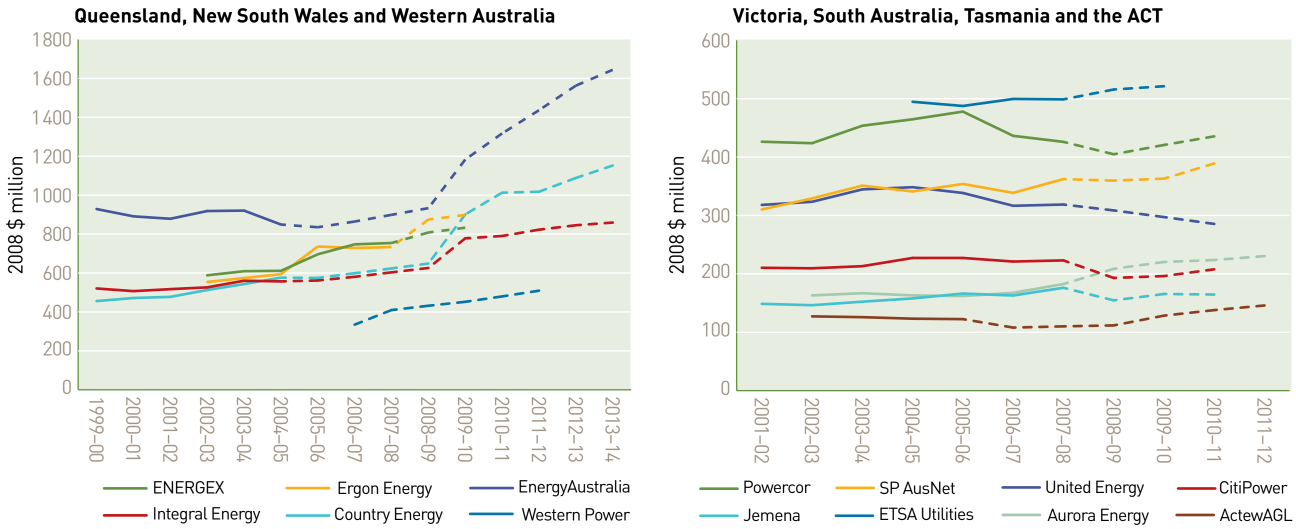
### 6.5.2 Return on assets

A common financial indicator for a business is its return on assets. The ratio is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 6.7 sets out the returns on assets for distribution businesses in the NEM, where data are available. Over the past seven years, the privately owned businesses in Victoria and South Australia tended to yield returns of about 8–12 per cent. Returns for these businesses were consistently higher than regulatory forecasts of 7–9 per cent. The government owned distribution businesses in New South Wales, Queensland and Tasmania achieved returns ranging from 4 per cent to 10 per cent.

A variety of factors can affect performance in this area. These include differences in the demand and cost environments faced by each business, and variances in demand and costs outcomes compared with those forecast in the regulatory process.

13 Western Power has proposed, for the regulatory period 2009–10 to 2011–12, that capital contributions be excluded from the RAB.

## Figure 6.6
### Electricity distribution network revenues




Notes:

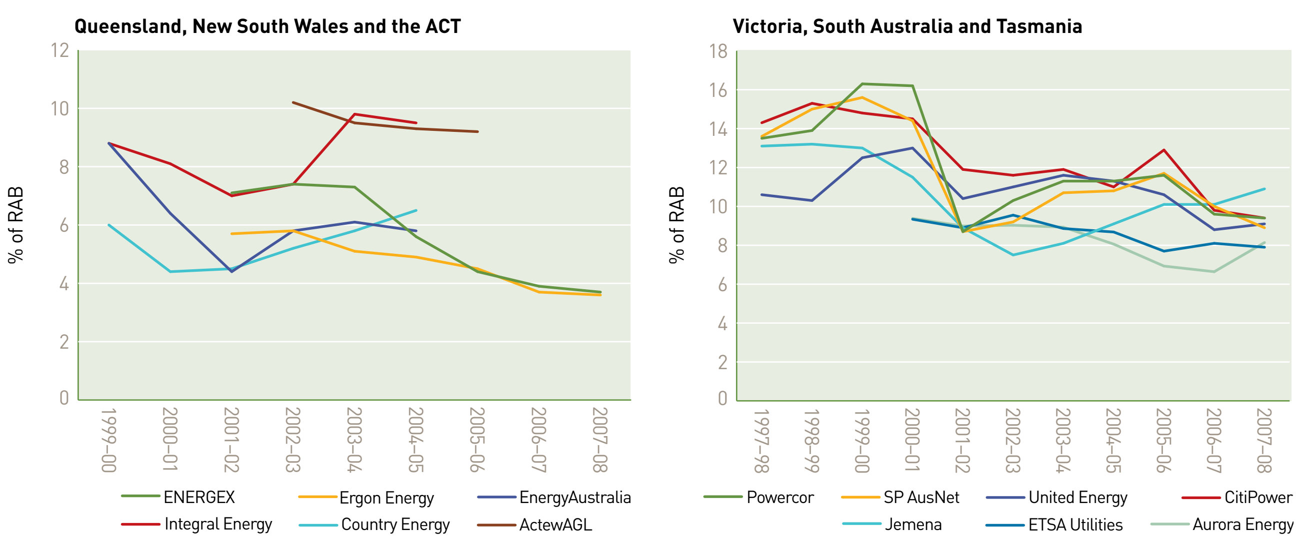
Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as provided in regulatory determinations (except for Western Australia, for which forecasts for 2009–10 to 2011–12 are based on the ERA's draft decision).

Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

## Figure 6.7
### Electricity distribution network return on assets

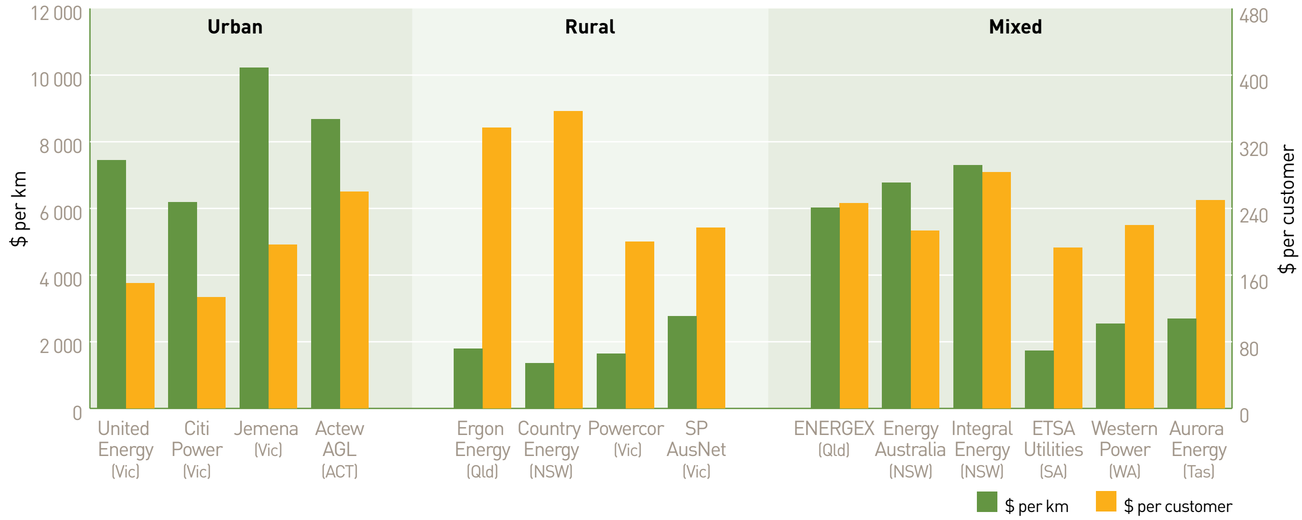



RAB, regulated asset base.

Note: Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).

Figure 6.8
**Forecast operating and maintenance expenditure—electricity distribution networks, 2008–09**




Note: Forecast data for 2008–09 are converted to June 2008 dollars. Victorian data are for the calendar year 2008.

Sources: Regulatory determinations published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

## 6.5.3 Operating and maintenance expenditure

Figure 6.8 charts forecast operating and maintenance expenditure for each network on per kilometre and per customer bases in 2008–09. The forecasts reflect regulatory allowances for each network to cover efficient operating and maintenance expenditure. There is a range of outcomes in this area, reflecting differences in customer and load densities, the scale and condition of the networks, geographic factors and reliability requirements. Normalising on a per kilometre basis tends to bias against high density urban networks with relatively short line lengths—reflected in the high outcomes for the three Victorian urban networks and the ACT network—while normalising on a per customer basis tends to bias against low density rural networks such as the Ergon Energy and Country Energy networks.

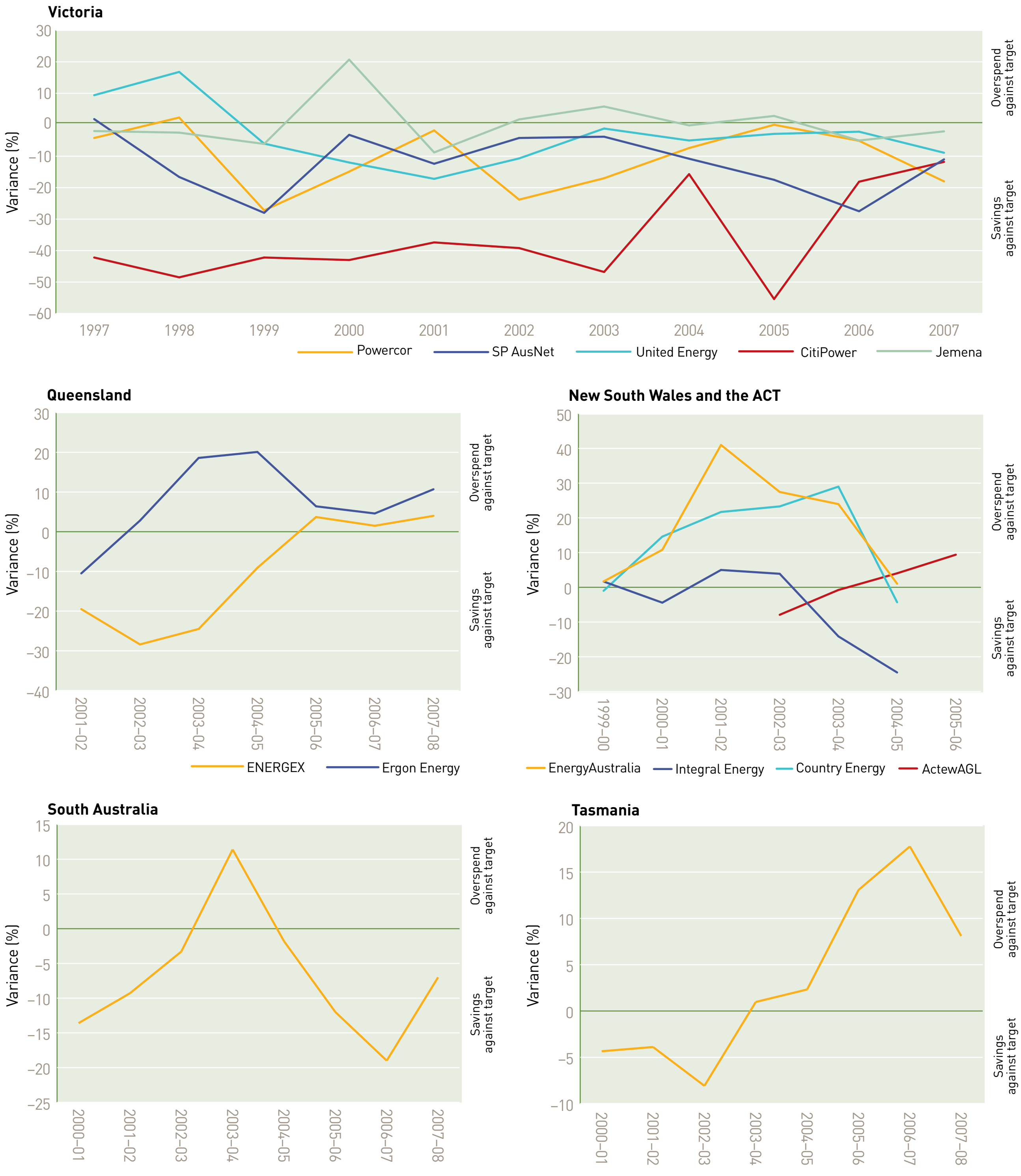
The AER published details in June 2008 of an efficiency benefit sharing scheme as part of the national framework for distribution regulation.[14] The scheme provides incentives for businesses to reduce their spending against benchmarks through efficient operating practices. It applies uniformly to all distribution businesses. The AER will first apply the scheme to the Queensland and South Australian networks from July 2010.

The scheme provides incentives for a distribution business to make efficient expenditure, by allowing it to retain efficiency gains for five years after a gain is made. A benchmark level of expenditure is used to determine revenue adjustments. Under the national scheme, the distribution business retains 30 per cent of efficiency gains against the benchmark, with the remaining 70 per cent being returned to customers through lower prices.

14 AER, *Electricity distribution network service providers: efficiency benefit sharing scheme, final decision*, Melbourne, June 2008.

## Figure 6.9

**Operating and maintenance expenses of electricity distribution networks—variances from target**




Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).

Over time, the national scheme will replace the current state based incentive schemes that jurisdictional regulators administer in the NEM. Figure 6.9 compares actual expenditure against target expenditure for each network under the state based schemes. A positive variance indicates that actual expenditure exceeded the benchmark in that year—that is, the distribution business overspent. A negative variance indicates underspending against the benchmark. A trend of negative variances over time may suggest a positive response to efficiency incentives. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. The network businesses have some flexibility in managing their expenditure over the regulatory period, so timing considerations may affect the data. Delays in completing a project may also affect expenditure.

Figure 6.9 indicates that the South Australian network and most Victorian networks underspent against their forecast allowances for most or all of the charted period. The Queensland networks recorded small but consistent overspends of up to 10 per cent from 2005–06. The Tasmanian network consistently overspent from 2003–04.

## 6.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service performance to reduce costs. Recognising these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service.

Quality of service monitoring for electricity distribution typically relates to:

- reliability (the continuity of electricity supply through the network)
- technical quality (for example, voltage stability)
- customer service (for example, on-time provision of services and the adequacy of call centre performance).

All jurisdictions regulate the service performance of distribution networks through:

- the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set in legislation, regulations, licences and codes (possibly with sanctions for non-compliance)
- GSLs (relating to network reliability, technical quality of service and customer service) that require, if not met, a network business to pay affected customers.

The legislated service standards are designed to ensure distribution businesses maintain appropriate levels of performance. GSL schemes ensure distribution businesses do not have an incentive to neglect regions or individual customers within their network.
In addition to these measures, some jurisdictions have applied financial incentive schemes for distribution businesses to maintain and improve service performance over time. With the shift to national distribution regulation, the AER published in 2009 details of a national service target performance incentive scheme that will apply, over time, to all distribution networks.

In the future, the AER will publicly report on the service performance of distribution businesses. It will consult with stakeholders on the reporting measures and future reporting arrangements.

## 6.6.1 Reliability

Reliability refers to the continuity of electricity supply to customers, and it is a key service performance indicator. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM. Relatively few outages originate in the generation and transmission sectors.[15]

A reliable distribution network keeps interruptions or outages in the transport of electricity down to efficient levels. It would be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome requires assessing the value of reliability to the community (measuring the impact on services) and the willingness of customers to pay. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. A 1999 Victorian study found more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[16] However, South Australian surveys in 2003 and 2007 indicated few customers were willing to pay for improvements in service. The 2007 survey found only 13 per cent of customers were willing to pay more for service improvement, with no significant difference in response between those experiencing high and low reliability.[17]

Surveys of consumer preferences do not necessarily capture all benefits from improved supply reliability, particularly those benefits from avoiding disruption to essential services. In a review of minimum service standards and GSLs in Queensland, Evans & Peck concluded, considering all impacts, that customers as a community value improved reliability.[18]

Various factors, both planned and unplanned, can impede network reliability:

- A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the supply of electricity to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues if part of a network has inadequate maintenance or is used near its capacity limits at times of peak demand. These factors sometimes occur in combination.

The impact of a distribution outage tends to be localised to a part of the network and depends on customer load, the design of the network and the time taken by a distributor to restore supply after an interruption. Maintenance practices are an important factor in reducing the number of outages and the time it takes to reconnect supply. Distribution businesses undertake large maintenance programs that include asset inspections and repairs, vegetation clearing and emergency response.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether it is satisfactory. The standards account for the trade-off between improved reliability and cost. Ultimately, customers must pay for the cost of investment, maintenance and other solutions needed to deliver a reliable power system.

The trade-offs between improved reliability and cost have resulted in standards for distribution networks being less stringent than for generation and transmission.



15 See AER, *State of the energy market 2007, essay B*, Melbourne, 2007, pp. 38–53.

16 KBA and Powercor, *Understanding customers' willingness to pay: components of customer value in electricity supply*, Melbourne, 1999.

17 The 2003 survey found a willingness to pay for improvements in service only to poorly served consumers. On this basis, ESCOSA has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–2010 Electricity distribution price determination, part A*, Adelaide, April 2005; KPMG, *Consumer preferences for electricity service standards*, Adelaide, March 2003; and McGregor Tan Research, *Consumer preferences for electricity service standards*, Adelaide, November 2007.

18 Evans & Peck, *Queensland Competition Authority, Review of minimum service standards and guaranteed service levels*, Brisbane, December 2008, p. 49.

These less stringent standards also reflect the localised effects of distribution outages, compared with the potentially widespread geographic impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability. These factors help to explain why distribution outages account for such a high proportion of electricity outages in the NEM.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. A higher reliability standard is usually required, for example, for a central business district (CBD) network with a large customer base and a concentrated load density than for a highly dispersed rural network with a small customer base and a low load density. While the unit costs of improving reliability in a dispersed rural network are relatively high, an outage is likely to affect few customers. Conversely, the unit costs of improving reliability in a high density urban network are relatively low, and an outage is likely to affect many customers.

## Reliability data

All jurisdictions have their own monitoring and reporting frameworks for reliability. In addition, the Steering Committee on National Regulatory Reporting Requirements (SCONRRR)[19] has adopted four indicators of distribution network reliability that are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table 6.3). The indicators do not distinguish between the nature and size of loads affected by supply interruptions.

In most jurisdictions, distribution businesses report performance against the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI) indicators. The national service performance incentive scheme, published in June 2008, includes the SAIDI and SAIFI indicators.[20]

**Table 6.3 Reliability measures—electricity distribution**

| INDEX | NAME | DESCRIPTION |
|---|---|---|
| SAIDI | System average interruption duration index | Average total number of minutes that a customer is without electricity in a year (excludes interruptions of one minute or less) |
| SAIFI | System average interruption frequency index | Average number of times a customer's supply is interrupted per year |
| CAIDI | Customer average interruption duration index | Average duration of each interruption (minutes) |
| MAIFI | Momentary average interruption frequency index | Average number of momentary interruptions (of one minute or less) per customer per year |

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, Canberra, 2002.

Regulators audit, analyse and publish reliability outcomes, typically down to feeder level (CBD, urban and rural) for each network.[21] Tables 6.4 and 6.5 and figure 6.10 estimate historical SAIDI and SAIFI data for NEM jurisdictions. Some data from Western Australia are also provided. In the future, the AER will report on reliability outcomes as part of its performance reporting on the distribution sector.

The data in tables 6.4 and 6.5 and figure 6.10 reflect total outages experienced by distribution customers. In general, the data have not been normalised to exclude distribution outages that are beyond the reasonable control of the network operator—for example, outages that originate in the generation and transmission sectors, and outages caused by external factors such as extreme weather. The data for Queensland in 2005–06 and New South Wales in 2006–07, however, have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise severely distort the data.

19 SCONRRR is a working group established by the Utility Regulators Forum.

20 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, June 2008. See section 6.6.4.

21 In New South Wales, the distribution businesses publish these data in the first instance. The regulator (IPART) periodically publishes summary data.

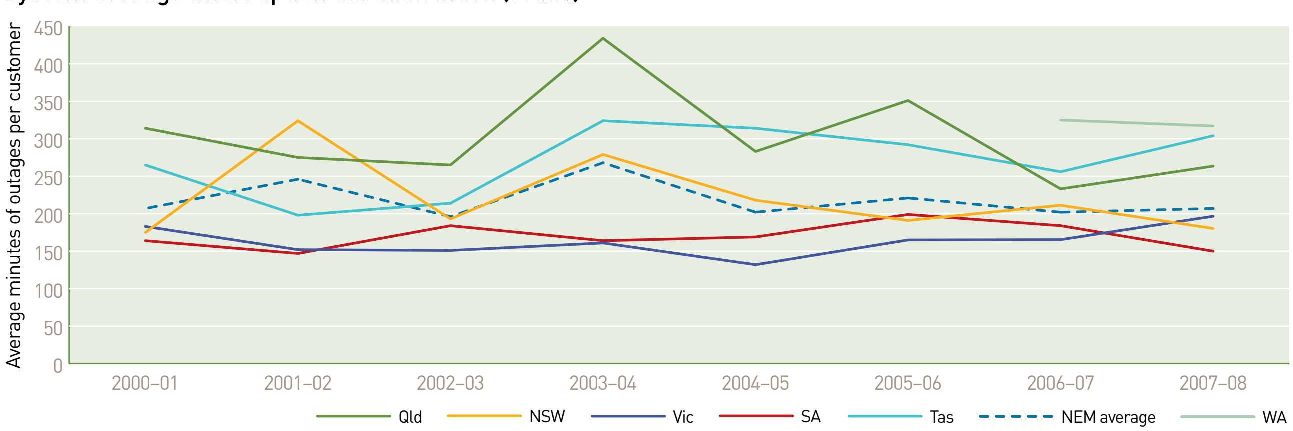
**Table 6.4 System average interruption duration index (SAIDI) (minutes)**

| | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 | 2006–07 | 2007–08 |
|---|---|---|---|---|---|---|---|---|
| Queensland | 331 | 275 | 265 | 434 | 283 | 353 | 231 | 264 |
| New South Wales | 175 | 324 | 193 | 279 | 218 | 191 | 211 | 180 |
| Victoria | 183 | 152 | 151 | 161 | 132 | 165 | 165 | 197 |
| South Australia | 164 | 147 | 184 | 164 | 169 | 199 | 184 | 150 |
| Tasmania | 265 | 198 | 214 | 324 | 314 | 292 | 256 | 304 |
| NEM weighted average | 211 | 246 | 196 | 268 | 202 | 221 | 202 | 207 |
| Western Australia | | | | | | | 325 | 317 |

**Table 6.5 System average interruption frequency index (SAIFI)**

| | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 | 2006–07 | 2007–08 |
|---|---|---|---|---|---|---|---|---|
| Queensland | 3.0 | 2.8 | 2.7 | 3.4 | 2.7 | 3.1 | 2.1 | 2.4 |
| New South Wales | 2.5 | 2.6 | 1.4 | 1.6 | 1.6 | 1.8 | 1.9 | 1.7 |
| Victoria | 2.1 | 2.0 | 2.0 | 2.2 | 1.9 | 1.8 | 1.9 | 2.1 |
| South Australia | 1.7 | 1.6 | 1.8 | 1.7 | 1.7 | 1.9 | 1.8 | 1.5 |
| Tasmania | 2.8 | 2.3 | 2.4 | 3.1 | 3.1 | 2.9 | 2.6 | 2.6 |
| NEM weighted average | 2.4 | 2.4 | 1.9 | 2.2 | 1.9 | 2.1 | 2.0 | 1.9 |
| Western Australia | | | | | | | 3.3 | 3.3 |

**Figure 6.10**
**System average interruption duration index (SAIDI)**




Notes for tables 6.4 and 6.5 and figure 6.10:

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year ending in that period.

Sources for tables 6.4 and 6.5 and figure 6.10: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates in the development of historical data.

From a customer perspective, the unadjusted data presented here are relevant, but an assessment of distribution network performance should normalise data to exclude external sources of interruption. The SCONRRR agreed that reliability data should, in some circumstances, be normalised to exclude interruptions beyond the control of a network business.

Until recently, there was no consistent approach to determining exclusions.[22] Now, the AER national service target performance incentive scheme (published in May 2009) adopts a consistent approach to exclusions, based on a standard set by the Institute of Electrical and Electronics Engineers. The standard is used in a number of Australian jurisdictions. In addition, the scheme identifies events that should be excluded.[23] The impact of excluded events is considered later in this chapter.

A number of issues limit the validity of comparing performance across the networks. In particular, the data rely on the accuracy of the network businesses' information systems, which may vary considerably. There are also differences in design, geographic conditions and historical investment across the networks. As noted, differences in customer density and load density can affect the costs and benefits of achieving high reliability. More generally, each jurisdiction historically took a different approach to approving and reporting excluded events and, until recently, there has been no consistent approach to auditing performance outcomes.

Noting these caveats, the SAIDI data indicate that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the past few years, with recent improvements in some jurisdictions. The NEM-wide SAIDI was generally 200–250 minutes from 2000–01 to 2007–08, but with significant regional variations.

The average duration of outages per customer has tended to be lower in Victoria and South Australia than elsewhere, despite some community concerns in the 1990s that privatisation might adversely affect service quality. Outage duration has tended to fall in New South Wales since 2003–04, and in 2007–08 that state recorded the second lowest outage rate behind South Australia. Average reliability (as measured by SAIDI) is weaker in Queensland and Tasmania than in other NEM jurisdictions. Queensland is subject to significant variations in performance, partly as a result of its large and widely dispersed rural networks, and extreme weather events. These characteristics make Queensland more vulnerable to outages than are some other jurisdictions, although it has recorded improvements in reliability since 2003–04. Data for Western Australia indicate that outage duration has recently been higher in that state than in the NEM jurisdictions.

The SAIFI data appear to show an improvement in the average frequency of outages across the NEM since 2000. The average frequency of outages is higher in Queensland than in other mainland jurisdictions, although that state's performance improved over 2006–07 and 2007–08. On average, distribution customers in the mainland NEM regions experience outages around twice a year. The rate has been a little higher in Tasmania. Western Australian customers experience outages around three times a year.

The recent improvements in reliability in New South Wales and Queensland are consistent with the rising investment trends noted in section 6.4. In Queensland, the government acted to improve reliability when a 2004 review (the Somerville review) found distribution service performance was unsatisfactory.[24] The government introduced performance requirements aimed at improving reliability by 25 per cent by 2010.

22 The SCONRRR definitions of SAIDI and SAIFI exclude outages that exceed a threshold SAIDI impact of 3 minutes; outages that are caused by exceptional natural or third party events; and outages for which the distribution business cannot reasonably be expected to mitigate the effect by prudent asset management.

23 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, May 2009, section 6.7.

24 For background on the Somerville review and Queensland's reliability issues, see AER, *State of the energy market 2007*, Melbourne, 2007, p. 53.

In New South Wales, licensing requirements relating to network design, reliability and performance have been gradually enhanced, requiring greater expenditure by the network businesses to ensure compliance.

### Reliability of distribution networks by feeder

Given the diversity of network characteristics, it is often more meaningful to compare reliability by feeder category rather than across networks as a whole. There are four categories of feeder, based on geographic location (table 6.6).

**Table 6.6 Feeder categories**

| FEEDER CATEGORY | DESCRIPTION |
|---|---|
| CBD | A feeder that predominately supplies commercial, high rise buildings through an underground distribution network containing significant interconnection and redundancy compared with urban areas |
| Urban | A feeder that is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 megavolt amperes per kilometre |
| Rural short | A feeder that is not a CBD or urban feeder, with a total feeder route length less than 200 kilometres |
| Rural long | A feeder that is not a CBD or urban feeder, with a total feeder route length greater than 200 kilometres |

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, Canberra, 2002.

Figures 6.11a–d set out the average duration of supply interruptions per customer (SAIDI) for each feeder type, subject to data availability. The charts distinguish between outages that are deemed within the reasonable control of the networks (normalised outages) and outages deemed beyond their control. The latter exclusions cover outages that originate in the generation and transmission sectors, and outages caused by external events such as extreme weather. Generally, it would be unreasonable to assess network performance unless excluding the impact of these external factors. Total network outages in a period are the sum of the normalised and excluded data.

Meaningful comparisons across jurisdictions—even based on the normalised data—are difficult given the differences in approach to exclusions and in auditing practices. Any attempt to compare performance should also account for geographic, environmental and other differences across the networks. That said, CBD and urban customers tend to experience better network reliability than rural customers.

The variations in performance across feeder types reflect that reliability standards account for the differing cost–benefit reliability trade-offs in each part of a network. To illustrate, a network outage on a CBD feeder is likely to have more severe economic consequences than from a similar outage on a remote rural feeder where customer bases and loads are more dispersed. Similarly, the unit costs of improving reliability in a high density urban network will be lower than in a dispersed rural network that is exposed to more variable weather and where it is more difficult to access lines to identify and repair faults. For these reasons, CBD networks are designed for higher reliability than other feeders are, and they use underground feeders, which are less vulnerable to outages.

Figure 6.11a

CBD feeders—average duration of supply interruptions per customer (SAIDI)

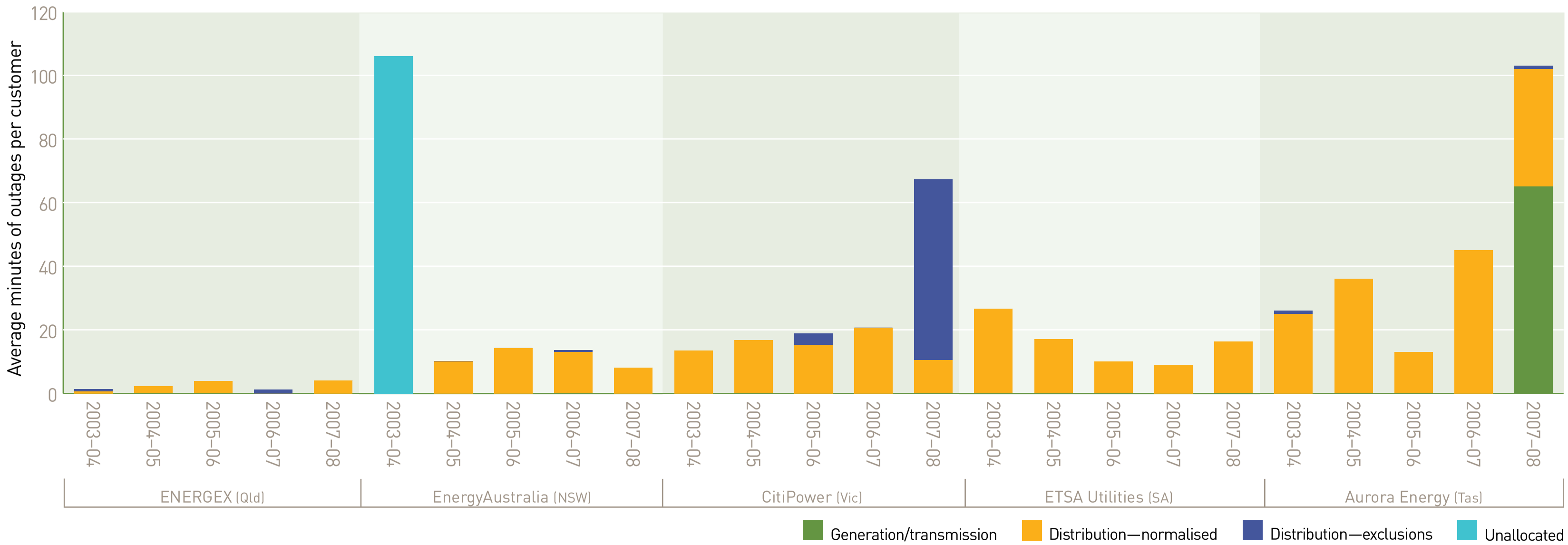



Figure 6.11b

Urban feeders—average duration of supply interruptions per customer (SAIDI)

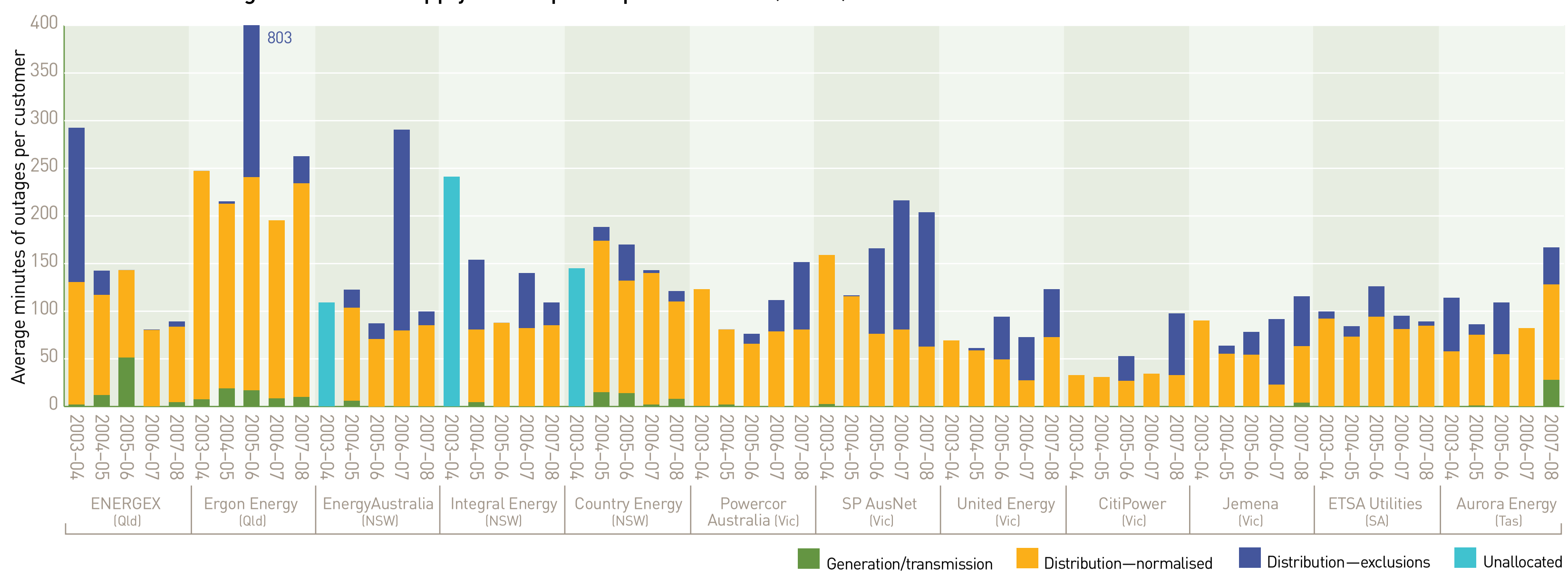


Figure 6.11c

Rural short feeders—average duration of supply interruptions per customer (SAIDI)

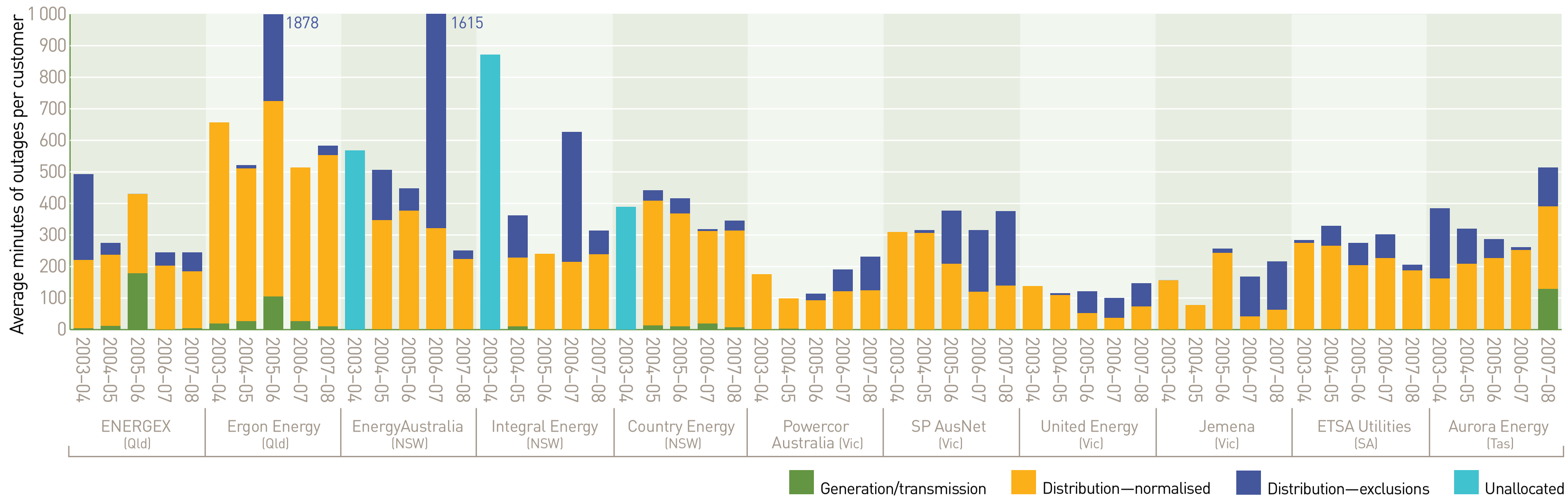
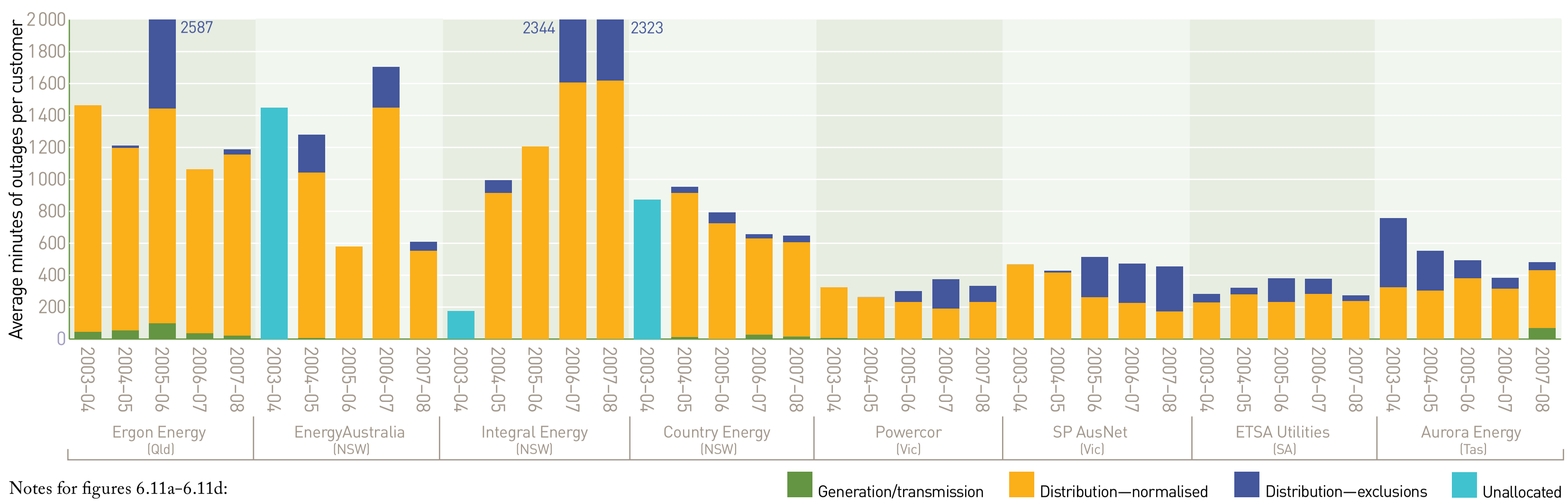



Figure 6.11d

Rural long feeders—average duration of supply interruptions per customer (SAIDI)




Notes for figures 6.11a–6.11d:

Victorian data are for the calendar year ending in that period.

Unallocated data do not provide a breakdown across categories.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas), EnergyAustralia, Integral Energy and Country Energy.

In summary, in the period from 2003–04 to 2007–08:

- CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 20 minutes per year. In 2007 CitiPower (Victoria) recorded unadjusted outages totalling 67 minutes—more than three times the level experienced in the previous five years. Most of these outages were the result of three excluded events, including load shedding during the 16 January 2007 bushfires. Unadjusted outages in Aurora Energy's (Tasmania) network averaged more than 100 minutes per customer. The increase in outages relative to the previous year was due to issues in the generation and transmission sectors.
- Urban customers typically experienced outages totalling around 50–150 minutes per year. Normalised outage time tended to be lowest for those networks with less dispersed customer bases. Networks in several jurisdictions experienced significant interruptions that were excluded from the normalised data. Extreme weather caused significant exclusions for Queensland in 2005–06 and New South Wales in 2006–07. SP AusNet (Victoria) had significant excluded events affecting its urban feeders for each of the last three years in the data period. The normalised data indicate that reliability was reasonably stable or improving over time in most networks.
- Rural short customers typically experienced normalised outages of around 100–300 minutes per year, with outages tending to be highest in New South Wales and Queensland. Ergon Energy (Queensland) customers typically experienced over 500 minutes of normalised outages. Weather related factors led to major exclusions in Queensland in 2005–06 and New South Wales in 2006–07.
- With a feeder route length of more than 200 kilometres, rural long customers experienced the least reliable electricity supply. Rural long customers in Victoria, South Australia and Tasmania experienced outages of around 200–400 minutes per year on average. The performance of the New South Wales and Ergon Energy (Queensland) networks was more variable, ranging from 600 minutes of outages to over 2000 minutes. In 2007–08 rural long customers serviced by Integral Energy (New South Wales) experienced normalised outages of over 1600 minutes (and total outages of over 2300 minutes) for the second year running.

### 6.6.2 Technical quality of supply

The technical quality of supply in a distribution network can be affected by issues such as voltage dips, swells and spikes, and television or radio interference. Some problems are network related (for example, the result of a network limit or fault), but others may be traced to an environmental issue or to a network customer.

Network businesses report on the technical quality of supply by disaggregating complaints into their underlying causes and categorising them. The complaint rate for technical quality of supply issues since 2004–05 has been less than 0.1 per cent of customers for most mainland distribution networks in the NEM. ENERGEX and Ergon Energy (Queensland) recorded complaint rates of 0.1 per cent and 0.3 per cent of customers respectively in 2007–08, with the performance of these networks having improved steadily since 2004–05. Western Power and Horizon Power (Western Australia) had complaint rates of 0.2 per cent and 0.3 per cent of customers respectively in 2007–08. Aurora Energy (Tasmania) recorded a complaint rate of 0.2 per cent of customers in 2007–08, lower than in the previous five years. Issues arise, however, when making performance comparisons across jurisdictions. In particular, the definition of 'complaint' adopted by each business may vary.

### 6.6.3 Customer service

Network businesses report on their responsiveness to a range of customer service issues, including:

- timely connection of services
- timely repair of faulty street lights
- call centre performance
- customer complaints.

Tables 6.7 and 6.8 provide a selection of customer service data for the networks. As noted, performance comparisons are difficult, given the significant differences across networks, as well as possible differences in definitions and in information, measurement and auditing systems.

Network performance in the timely provision of services in 2007–08 was broadly in line with that of previous years. ENERGEX recorded a significant increase in the number of late connections, and the New South Wales networks recorded longer average times for street light repairs. Call centre performance was similar to that of previous years, with the New South Wales and most Victorian networks recording slight improvements in 2007–08.

### 6.6.4 Service performance incentive schemes

Victoria and South Australia have applied financial incentive schemes for their distribution businesses to maintain and improve service performance over time. The model is an 's-factor' incentive scheme, similar to that applied to transmission networks.[25] The South Australian scheme focuses on customers with poor reliability outcomes.

The AER published details in May 2009 of an incentive scheme for service target performance as part of the national framework for distribution regulation.[26]

The scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets. The targets relate to reliability of supply (duration and frequency of outages) and customer service. The results are standardised for each network to derive an 's-factor' that reflects deviations from target performance levels.

The national scheme includes a GSL component, which provides payments to customers that receive service below predetermined thresholds (for example, failure to attend service appointments). The GSL component does not apply where the distribution business is subject to jurisdictional GSL obligations (see section 6.6.5).

The national scheme is based on existing state based incentive schemes in Victoria and South Australia, so has regard to industry and community expectations. Over time, the national scheme will replace the state based schemes. The AER will first apply the national scheme in its current price reviews of the Queensland and South Australian distribution networks, scheduled to take effect in July 2010. While the AER considers the scheme should apply on a consistent basis nationally where practical, there is some flexibility to allow for transitional issues and the differing circumstances and operating environments of each network. The scheme will likely evolve over time to allow for factors such as changes in energy industry technology, climate change policies and other issues affecting customer expectations of service performance and the wider operating environment for the distribution sector. Table 6.9 shows how the scheme will apply in each jurisdiction.

The AER will publicly report on the service performance of distribution businesses in the future. It will consult with stakeholders on the reporting measures and future reporting arrangements.

25 The use of s-factor schemes is discussed in the context of electricity transmission in section 5.6 of this report.
26 AER, *Electricity distribution network service providers: service target performance incentive scheme, final decision*, Melbourne, June 2008.

**Table 6.7** Timely provision of service by electricity distribution networks

| NETWORK | PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE | | | | PERCENTAGE OF STREETLIGHT REPAIRS COMPLETED AFTER AGREED DATE | | | | AVERAGE NUMBER OF DAYS TO REPAIR FAULTY STREETLIGHT | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2004–05 | 2005–06 | 2006–07 | 2007–08 |
| QUEENSLAND[1] | | | | | | | | | | | | |
| ENERGEX | 3.98 | 0.62 | 0.54 | 10.79 | 5.4 | 4.8 | 7.6 | 4.8 | 3.5 | 4.5 | 4.0 | 3.0 |
| Ergon Energy | 6.62 | 0.84 | 0.49 | 0.72 | 9.7 | 21.5 | 17.9 | … | 2.8 | 3.9 | 3.5 | … |
| NEW SOUTH WALES[2] | | | | | | | | | | | | |
| EnergyAustralia | 0.01 | 0.02 | 0.02 | 0.01 | 6.6 | 6.0 | 1.0 | 2.4 | 8.0 | 9.0 | 6.0 | 12.0 |
| Integral Energy | 0.01 | 0.02 | 0.02 | 0.01 | 5.5 | 0.9 | 1.0 | 2.4 | 2.0 | 2.0 | 2.0 | 3.0 |
| Country Energy | 0.02 | 0.02 | 0.02 | 0.01 | 1.3 | 1.0 | 1.0 | 2.4 | 9.0 | 8.0 | 8.0 | 10.0 |
| VICTORIA | | | | | | | | | | | | |
| Powercor | 0.13 | 0.12 | 0.06 | 0.04 | 0.3 | 0.1 | 3.4 | 1.8 | 2.0 | 2.0 | 2.2 | 2.0 |
| SP AusNet | 0.03 | 0.21 | 2.40 | 2.66 | 1.0 | 0.8 | 0.1 | 0.0 | 2.0 | 2.0 | 1.4 | 1.0 |
| United Energy | 0.12 | 0.05 | 0.29 | 0.05 | 0.8 | 0.2 | 0.4 | 0.2 | 1.4 | 1.0 | 1.0 | 1.0 |
| CitiPower | 0.00 | 0.02 | 0.03 | 0.05 | 7.8 | 11.4 | 5.8 | 8.4 | 2.3 | 3.0 | 2.2 | 2.2 |
| Jemena | 0.14 | 0.12 | 0.09 | 0.19 | 6.1 | 6.9 | 1.1 | 0.9 | 2.0 | 3.0 | 2.4 | 1.9 |
| SOUTH AUSTRALIA[1] | | | | | | | | | | | | |
| ETSA Utilities | 0.91 | 1.33 | 0.51 | 1.30 | 4.5 | 5.5 | 2.6 | 1.8 | 3.8 | 3.6 | 2.6 | 3.0 |
| WESTERN AUSTRALIA | | | | | | | | | | | | |
| Western Power | … | 20.90 | 20.40 | 18.80 | … | 8.4 | 35.0 | 34.7 | … | … | 6.5 | … |
| Horizon Power | … | 0.00 | 0.00 | 15.60 | … | 0.0 | 23.0 | 15.1 | … | 2.0 | 6.8 | … |
| TASMANIA | | | | | | | | | | | | |
| Aurora Energy | … | 0.15 | 0.14 | 2.00 | 10.5 | 12.3 | 14.0 | … | … | … | … | … |

1. Completed connections data for Queensland and South Australia include new connections only.
2. New South Wales completed connections data from 2005-06 and street light repair percentage data from 2006-07 are state averages.

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

## Table 6.8 Call centre performance by electricity distribution networks

| NETWORK | PERCENTAGE OF CALLS ABANDONED BEFORE REACHING HUMAN OPERATOR | | | | PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS | | | |
|---|---|---|---|---|---|---|---|---|
| | 2004–05 | 2005–06 | 2006–07 | 2007–08 | 2004–05 | 2005–06 | 2006–07 | 2007–08 |
| **QUEENSLAND** | | | | | | | | |
| ENERGEX | 2.2 | 3.9 | 3.0 | 3.8 | 89.4 | 89.4 | 79.1 | 96.3 |
| Ergon Energy | 2.8 | 3.5 | 2.3 | 2.5 | 85.0 | 85.1 | 87.0 | 86.2 |
| **NEW SOUTH WALES AND THE ACT** | | | | | | | | |
| EnergyAustralia | 10.5 | 10.5 | 15.7 | 10.8 | 44.6 | 81.3 | 74.3 | 81.1 |
| Integral Energy | 6.0 | 3.2 | 8.7 | 3.8 | 81.0 | 89.0 | 70.9 | 96.2 |
| Country Energy | 41.2 | 42.6 | 31.1 | 27.4 | 48.4 | 47.2 | … | 61.4 |
| ActewAGL | 16.9 | 22.5 | 21.1 | 14.0 | 65.6 | 39.7 | 62.4 | 70.5 |
| **VICTORIA** | | | | | | | | |
| Powercor | 5.9 | 7.0 | 7.0 | 4.0 | 90.9 | 88.7 | 86.7 | 89.4 |
| SP AusNet | 8.8 | 6.0 | 9.0 | 7.0 | 79.8 | 82.7 | 92.3 | 91.2 |
| United Energy | 7.7 | 24.0 | 18.0 | 17.0 | 75.6 | 73.8 | 72.9 | 74.0 |
| CitiPower | 10.8 | 10.0 | 5.0 | 4.0 | 88.2 | 89.2 | 85.7 | 87.2 |
| Jemena | 0.9 | 5.0 | 7.0 | 13.0 | 73.8 | 75.2 | 77.4 | 79.9 |
| **SOUTH AUSTRALIA** | | | | | | | | |
| ETSA Utilities | 4.4 | 4.0 | 3.0 | 3.0 | 86.9 | 85.2 | 89.3 | 88.7 |
| **WESTERN AUSTRALIA** | | | | | | | | |
| Western Power | … | … | 0.1 | 4.3 | … | … | … | 79.0 |
| Horizon Power | … | … | 9.4 | 4.5 | … | … | 70.0 | 83.0 |
| **TASMANIA** | | | | | | | | |
| Aurora Energy | 1.0 | 9.3 | 5.6 | 4.0 | … | … | … | … |

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), the ERA (WA), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

## Table 6.9 Service target performance incentive scheme for distribution businesses to be applied by the AER

| NEW SOUTH WALES AND THE ACT | SOUTH AUSTRALIA | QUEENSLAND | VICTORIA |
|---|---|---|---|
| The national scheme will apply as a reporting requirement, but without financial incentives attached to targets.<br><br>The AER will apply reliability of supply and customer service components.<br><br>No GSL components will apply. | The national scheme will likely apply, with ±5 per cent of businesses' revenue at risk under the scheme.<br><br>Targets will be attached to reliability of supply and customer service components.<br><br>No GSL components will apply, because a jurisdictional GSL scheme applies. | The national scheme will likely apply, with ±2 per cent of revenue at risk under the scheme.<br><br>Targets will be attached to reliability of supply and customer service components.<br><br>No GSL components will apply, because a jurisdictional GSL scheme applies. | The national scheme will likely apply, with ±5 per cent of revenue at risk under the scheme.<br><br>Targets will be attached to reliability of supply and customer service components.<br><br>The GSL component will apply, replacing the jurisdictional GSL, which ceases on 1 January 2011. |

Sources: New South Wales and the ACT distribution determinations, April 2009; Framework and approach papers for the Queensland, South Australian and Victorian networks.

**Table 6.10 Guaranteed service levels of electricity distribution networks**

| | NATIONAL (AER) | QLD[1] | NSW | VIC | SA | WA | TAS | ACT |
|---|---|---|---|---|---|---|---|---|
| RELIABILITY MEASURES | | | | | | | | |
| Duration of supply interruptions exceeds specified limit | $80 per interruption | $80 per interruption | $80 per interruption (maximum $320 per year) | $100–300 per year | $80–320 per interruption | $80 per interruption | $80–160 per interruption | $20 per interruption |
| Frequency of supply interruptions exceeds specified limit | $80 per interruption | $80 per year | $80 per year | $100–300 per year | $80–160 per year | | $80 per year | |
| Frequency of momentary supply interruptions (less than 1 minute) exceeds specified limit | | | | $25–35 per year | | | | |
| CUSTOMER SERVICE MEASURES | | | | | | | | |
| Wrongful disconnection | | $100 | | | | | | |
| Late connection | $50 per day (maximum $300) | $40 per day | $60 per day (maximum $300) | $50 per day (maximum $250) | $50 per day | | $30 per day (maximum $150) | $60 per day (maximum $300)[2] |
| Late reconnection | | $40 per day | | | | | | |
| Failure to attend a scheduled appointment on time | | $40 | $25 | $20 | $20 | | $30 | |
| Failure to respond to a complaint in designated timeframe | | | | | | $20 | | $20 |
| Failure to give sufficient notice of a planned interruption | $50 | $20 (residential) $50 (business) | $20 | | | $20 | $30 | $50 |
| Planned interruptions not completed in specified time | | | $20 | | | | | $50 |
| Late repair of street lights | $25 | | $15 | $10 | $20 per five or 10 day period | | $30 per day (maximum $150) | |
| Late response to an inquiry regarding loss of hot water | | $40 per day | | | | | | |
| Altered condition of property due to vegetation clearing | | | | | | | $30 | |

1. Queensland has a cap on payments of $320 per customer per year (excludes wrongful disconnection payments). The QCA has approved increases in compensation payments of about 30 per cent, to apply from 1 July 2010.
2. Includes the response time for a reported fault or damage.

### 6.6.5 Guaranteed service levels

The GSL schemes provide for payments to customers that experience poor service. They are not intended to provide legal compensation to customers, but to enhance service performance by distribution businesses.

A range of GSL schemes apply across the jurisdictions. With the shift to national distribution regulation, the AER published details in 2009 of a national GSL scheme as part of the service target performance incentive scheme (see section 6.6.4). But the jurisdictional schemes will continue in some instances: both the Essential Services Commission of South Australia (ESCOSA) and the QCA have indicated they will retain their jurisdictional schemes. However, the national scheme will likely apply to the Victorian networks in the next regulatory period.

The GSL schemes provide payments for poor service quality in areas such as streetlight repair, frequency and duration of supply interruptions, new connections and notice of planned interruptions. Table 6.10 details the performance criteria and associated compensation payments. Payments under the national scheme are made automatically to consumers if service is below target. This arrangement differs from most jurisdictional schemes under which payments are made only if affected customers apply.

Given each jurisdiction reports against different criteria, it is not possible to compare the performance of distribution businesses against GSL targets across jurisdictions. Further, given payments are generally made only if a customer applies, outcomes over time may reflect both changes in customer awareness and business performance.

The majority of GSL payments in 2007–08 in most jurisdictions related to the duration and frequency of supply interruptions exceeding specified limits. Payments in Queensland resulted mainly from wrongful disconnections and late connections.

- In Queensland, GSL payments in 2007–08 were the equivalent of $0.07 per customer for Ergon Energy and $0.09 per customer for ENERGEX.
- In New South Wales, GSL payments in 2007–08 were equivalent to $0.02 per customer. Eighty per cent of the payments were made by Country Energy, with EnergyAustralia and Integral Energy accounting for around 10 per cent each. There was a slight rise in total payments over the previous five years.
- In Victoria, GSL payments in 2007–08 were equivalent to $2.21 per customer—around one third higher than the previous year's. However, the performance of individual businesses varied. The majority of payments were made by the predominantly rural networks SP AusNet (81 per cent of total payments by Victorian businesses) and Powercor (18 per cent).
- In South Australia, GSL payments by ETSA Utilities fell by 74 per cent between 2005–06 and 2007–08. Payments in 2007–08 were the equivalent of $0.64 per customer.
- In Western Australia, Western Power's 2007–08 payments were equivalent to $0.26 per customer. This was an improvement on 2006–07 but above 2005–06 levels. Horizon Power's payments in 2007–08, equivalent to $0.06 per customer, were lower than those in the previous two years.
- In Tasmania, GSL payments in 2007–08 (equivalent to $2.00 per customer) were three times greater than the previous year's, but consistent with 2005–06 outcomes.

## 6.7 Policy developments in electricity distribution

Recent policy activity in the distribution sector has focused on network planning and operation and the approach to economic regulation. The following section summarises policy developments in these areas. Appendix A describes the institutional bodies responsible for developing and implementing energy policy.

### 6.7.1 Network planning and expansion

On 17 December 2008 the Ministerial Council on Energy (MCE) agreed to establish a national framework for distribution network planning.

As part of this process, the MCE directed the Australian Energy Market Commission (AEMC) to review the distribution network planning and expansion arrangements in the NEM. The AEMC submitted its final report to the MCE in September 2009.[27]

The planning framework, once finalised, is intended to ensure clear and efficient planning and investment processes. Recommendations include:

> requiring distribution businesses to publish annual planning reports looking forward a minimum of five years
> replacing the current regulatory test with a regulatory investment test for distribution—similar to the new test for transmission investment (see section 5.8.2)
> establishment of a demand-side engagement strategy to ensure that non-network solutions to address system limitations are fully considered.

## 6.7.2 Network connection

In March 2009 the MCE's network policy working group made its final recommendations on a national framework for the connection of customers to distribution networks.[28] The working group found the process for network connection should be simplified and streamlined. Its report recommended distribution businesses be required to have at least one standard connection service for a customer load category (for example, small customers) and at least one standard connection service for micro embedded generators.[29]

The working group suggested two possible methods for connection to a distribution network:

> standard connections, with a short period (five days) for a connection offer to be made following an application
> negotiated connections, to be provided on an individual basis and allow more time for offers to be prepared.

A national framework for electricity distribution connection will incorporate these recommendations. The framework is being drafted in 2009, with legislative proposals expected in 2010. Once implemented, it will provide a single customer framework for the provision of electricity and gas connections.

## 6.7.3 Total factor productivity approach

In 2008 the AEMC commenced a review of the total factor productivity (TFP) approach in energy regulation. TFP is a method that measures how businesses use resources to produce output. It exposes regulated businesses to competitive pressures by linking revenues to industry performance rather than the cost structures of specific businesses.

The AEMC will advise the MCE on the potential use of TFP assessments, in conjunction with the building block approach, to determine network revenues and price. The TFP assessment would be used to judge the reasonableness of network expenditure forecasts under the building block method. The AEMC has identified potential benefits from applying a TFP method, including:

> lower regulatory administrative costs
> reduced information asymmetry between regulated businesses and regulators
> stronger performance incentives to the regulated business.[30]

The AEMC expects to finish its review in April 2010, with any recommended rule changes to be considered by the MCE in June 2010. The review will consider:

> the strength of incentives for networks to pursue efficient costs and share efficiencies with customers
> whether the TFP framework leads to efficient investment with innovation and technical progress
> clarity, certainty and transparency in the regulatory framework and processes to reduce avoidable risks for service providers and customers.

27 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, Sydney, September 2009.
28 MCE Network Policy Working Group, *National connections framework for electricity distribution businesses, final report*, Canberra, March 2009.
29 A micro embedded generator is a generator with a rating below 10 kilovolt amperes (kVa) (for single phase power) or 30 kVa (for three phase power) that is connected to the distribution network.
30 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues: framework and issues paper*, Sydney, December 2008.

### 6.7.4 Climate change policy

The AEMC has conducted a review of the likely impacts of climate change policies—particularly the carbon pollution reduction scheme and expanded renewable energy target—on energy market frameworks. It released the final report in October 2009.[31]

The AEMC found the main challenges for distribution networks are the potential growth in embedded generation and the increased variability of network flows, leading to the need for more active management of demand. These changes would make network management more complex and require new investment in network infrastructure. Despite these challenges, the AEMC considered the current regulatory framework is sufficiently flexible to accommodate the evolving demands on network businesses.

The AEMC noted initiatives to facilitate innovation in the management of network reliability, including the demand management innovation allowance (see section 6.8.1). It recommended expanding the allowance to cover innovations in the connection of embedded generators to distribution networks.

## 6.8 Demand management and metering

### 6.8.1 Demand management

Demand management (or demand-side participation) relates to strategies to manage the growth in overall or peak demand for energy services. The objective is to reduce or shift demand, or implement efficient alternatives to network augmentation. Demand management in the NEM is constantly evolving, with a number of initiatives being implemented. The initiatives are primarily undertaken at the retail or distribution level and require cooperation between energy customers and suppliers.

The demand management programs trialled in Australia include:

> controlling the load for residential appliances such as air conditioners and pool pumps. Under these schemes, appliances are remotely switched off (or cycled on and off) at times of peak demand.
> providing price signals to consumers to encourage them to shift some energy consumption away from times of peak demand. Trialled methods for residential customers include time-of-use and critical peak pricing.[32] The strategies require advanced metering equipment and flexible tariff arrangements. Some distributors have entered into contracts with large energy customers to reduce consumption at peak times.
> supporting embedded generation, where back-up generation is enabled in large business facilities, as a substitute for network augmentation.

The regulatory process allows for funding to encourage these initiatives. The AER has launched demand management schemes for New South Wales and the ACT, Queensland, South Australia and Victoria. The schemes provide funding to trial and implement demand management solutions. Some of the schemes allow for the recovery of forgone revenue arising from lower demand for network services. Table 6.11 sets out how the schemes will apply in each jurisdiction.

In 2009 the AEMC completed a review of whether there are regulatory impediments to demand-side participation in the NEM.[33] The review investigated whether the current regulatory arrangements are biased towards expanding generation and network capacity to meet demand for electricity, rather than taking more cost-effective approaches to reduce demand.

The AEMC published a draft report in April 2009 that identified material barriers to demand-side participation that are attributable to regulated network businesses.

31 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009.

32 Critical peak pricing involves retailers charging a higher tariff at times of extreme demand. Retailers have some flexibility in when they can institute the higher price; however, there is usually a limit on the number of times the tariff can be used, along with requirements for customers to receive sufficient notice.

33 AEMC, *Demand side participation in the national electricity market, draft report*, Sydney, April 2009.

**Table 6.11 Demand management incentive schemes to be applied by the AER for electricity distribution businesses**

| NEW SOUTH WALES | THE ACT | SOUTH AUSTRALIA | QUEENSLAND | VICTORIA |
|---|---|---|---|---|
| In addition to a demand management innovation allowance, the New South Wales businesses are subject to a d-factor mechanism that allows businesses to recover:<br>> approved non-tariff based demand management implementation costs<br>> tariff based demand management implementation costs<br>> revenue forgone as a result of non-tariff based demand management initiatives. | The ACT distribution network business, ActewAGL, will receive a demand management innovation allowance. | In addition to a demand management innovation allowance, the South Australian network business, ETSA Utilities, is also subject to a forgone revenue mechanism that allows it to recover revenue forgone where demand is successfully reduced by expenditure of the innovation allowance. | The Queensland distribution network businesses, ENERGEX and Ergon Energy, will receive a demand management innovation allowance. | In addition to a demand management innovation allowance, Victorian network businesses are subject to a forgone revenue mechanism that allows it to recover:<br>> revenue forgone where demand is successfully reduced by expenditure of the innovation allowance<br>> an annual allowance to spend on demand management<br>> a forgone revenue component. |

The following are noteworthy:

> The current method for setting network prices penalises businesses that use demand management initiatives to defer capital expenditure.
> Businesses have limited financial incentives to innovate under current regulatory approaches. The AEMC considers that 'use it or lose it' funding for innovation may be a proportionate way of addressing such a barrier, by allowing network businesses to recover costs associated with approved innovation projects outside their normal operating or capital expenditure requirements.
> Variability in network connection, planning and consultation processes across network businesses is a barrier to effective demand-side participation.
> Price cap regulation provides networks with incentives to undertake socially efficient demand-side participation.[34]

The AEMC has also considered demand management issues for transmission networks. In response to a proposal from the Total Environment Centre, it implemented amendments to the Electricity Rules. These rule changes support the provision of information about projected network constraints to market participants. This information assists demand management service providers to participate actively in the market and consider efficient alternatives to network augmentation. The amendments relate to:

> network businesses' provision of specific information about forecast constraints in their annual planning reports
> the AER's treatment of non-network expenditure (including demand management activities) incurred by network businesses in future revenue determinations
> obligations on the AER when assessing revenue proposals, to account for whether the network businesses have demonstrated, and provided for, appropriate efficient non-network alternatives
> obligations on network businesses to provide information on appropriate non-network alternatives in their revenue proposals.[35]

## 6.8.2 Metering

Meters record the energy consumption of customers at the point of connection to the distribution network. Effective metering, when coupled with appropriate price signals, can encourage more active demand management by customers.

34 AEMC, *Demand side participation in the national electricity market, draft report*, Sydney, April 2009.
35 AEMC, *Rule Determination, National Electricity Amendment (Demand Management) Rule 2009*, Sydney, April 2009.

There are two main types of meter:

- The older style *accumulation meters* record the total consumption of electricity at a connection point, but not the time of consumption. Consumers are billed on solely the volume of electricity consumed.
- *Interval meters* are more sophisticated and record consumption in defined time intervals (for example, half hour periods). This allows time-of-use billing so the charge for electricity can be varied with the time of consumption. Industry generally uses interval meters.

Plans are being implemented at the national and state levels to introduce *smart meters*, which are an advanced type of interval meter. These meters have remote communication capabilities between retailers and customer that allow for remote meter reading and connection/disconnection of customers. Add-ons such as an in-house display may provide prices and other aspects of electricity consumption, as well as real time information on power outages. The meters are also compatible with technology that allows retailers and distribution businesses to manage loads to particular customers and appliances.

The take-up of smart meters has varied among jurisdictions:

- In New South Wales, distribution businesses are rolling out interval meters for customers using more than 15 megawatt hours of electricity a year. For smaller customers, interval meters are provided on a new and replacement basis. The New South Wales Government has committed to a full rollout of smart meters by 2017.
- The Victorian Government has initiated a program to provide smart meters to all customers over a four year period from 2009. In January 2009 the AER released a framework and approach paper that sets out the process for determining the prices that distribution businesses can charge for metering services.[36] The Victorian distributors have submitted to the AER budget applications for metering expenditure to 2011. The AER is scheduled to release a final determination on initial budgets and charges on 31 October 2009. Distribution businesses, after installing an interval meter for a customer, are entitled to reassign the customer to a time-of-use tariff.[37] In May 2009 the AER released notification requirements that a distribution business must provide to customers before this change can occur.[38]
- A number of other jurisdictions are rolling out smart meters on a new and replacement basis.

In 2007 the Council of Australian Governments (COAG) agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs. A cost–benefit assessment published in March 2008 found a national rollout would achieve a net benefit.[39] However, in June 2008 the MCE noted uncertainties in the levels of costs and benefits, and supported the implementation of trials and further analysis to help verify jurisdictional costs and benefits.[40]

The MCE is developing a framework to support a rollout of smart electricity meters in the NEM, noting that consistency between NEM and non-NEM jurisdictions will be sought as appropriate. The MCE is focusing on regulatory arrangements (including cost recovery arrangements), consumer protection measures and safety standards. A national stakeholder steering committee was established to lead the development of technical and operational aspects of the framework. The steering committee is also responsible for reviewing progress of jurisdictional pilots and trials.

The MCE has estimated the current process should result in more than 50 per cent of all Australian meters being replaced by 2017. It will consider a timetable for a further rollout of smart meters by June 2012.[41]

36 AER, *Framework and approach paper, Advanced metering infrastructure review 2009–11, final decision*, Melbourne, January 2009.

37 Where the customer consumes less than 20 megawatt hours of electricity per year.

38 AER, *Interval meter reassignment requirements, final decision*, Melbourne, May 2009.

39 NERA, *Cost benefit analysis of smart metering and direct load control overview report for consultation*, Prepared for the Smart Meter Working Group, Sydney, February 2008.

40 MCE, *Communiqué*, Canberra, 13 June 2008.

41 MCE, *Communiqué*, Canberra, 13 June 2008.